JUN 4 1982

105.1-2 Y3.N88:10/0916

NUREG-0916

ORIGINAL

Safety Evaluation Report

COMPLETED
361

related to the restart of
R. E. Ginna Nuclear Power Plant

Docket No. 50-244

Rochester Gas and Electric Corporation

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

May 1982

NOTICE

Availability of Reference Materials Cited in NRC Publications

Most documents cited in NRC publications will be available from one of the following sources:

1. The NRC Public Document Room, 1717 H Street, N.W.
   Washington, DC 20555
2. The NRC/GPO Sales Program, U.S. Nuclear Regulatory Commission,
   Washington, DC 20555
3. The National Technical Information Service, Springfield, VA 22161

Although the listing that follows represents the majority of documents cited in NRC publications, it is not intended to be exhaustive.

Referenced documents available for inspection and copying for a fee from the NRC Public Document Room include NRC correspondence and internal NRC memoranda; NRC Office of Inspection and Enforcement bulletins, circulars, information notices, inspection and investigation notices; Licensee Event Reports; vendor reports and correspondence; Commission papers; and applicant and licensee documents and correspondence.

The following documents in the NUREG series are available for purchase from the NRC/GPO Sales Program: formal NRC staff and contractor reports, NRC-sponsored conference proceedings, and NRC booklets and brochures. Also available are Regulatory Guides, NRC regulations in the *Code of Federal Regulations,* and *Nuclear Regulatory Commission Issuances.*

Documents available from the National Technical Information Service include NUREG series reports and technical reports prepared by other federal agencies and reports prepared by the Atomic Energy Commission, forerunner agency to the Nuclear Regulatory Commission.

Documents available from public and special technical libraries include all open literature items, such as books, journal and periodical articles, and transactions. *Federal Register* notices, federal and state legislation, and congressional reports can usually be obtained from these libraries.

Documents such as theses, dissertations, foreign reports and translations, and non-NRC conference proceedings are available for purchase from the organization sponsoring the publication cited.

Single copies of NRC draft reports are available free upon written request to the Division of Technical Information and Document Control, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at the NRC Library, 7920 Norfolk Avenue, Bethesda, Maryland, and are available there for reference use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from the American National Standards Institute, 1430 Broadway, New York, NY 10018.

GPO Printed copy price: $8.50

BEST DOCUMENT AVAILABLE

NUREG-0916

Safety Evaluation Report

related to the restart of
R. E. Ginna Nuclear Power Plant
Docket No. 50-244

Rochester Gas and Electric Corporation

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

May 1982

ABSTRACT

The report documents NRC's evaluation of the tube rupture which occurred at the R. E. Ginna Nuclear Power Plant on January 25, 1982. This plant, which is located in Wayne County, New York, is owned and operated by Rochester Gas and Electric Corporation. Based on the results of the evaluation, the staff recommends restart of the Ginna Plant.

TABLE OF CONTENTS

		Page
1.0	INTRODUCTION	1-1
2.0	BACKGROUND/SUMMARY	2-1
3.0	TRANSIENT ANALYSIS	3-1
3.1	Comparison of Plant Response with Previous Analyses	3-1
3.2	Sequence of Events	3-10
3.3	Steam Void Formation	3-10
3.4	Calculation of Leak Rate	3-13
3.5	Thermal Transient on the Reactor Coolant System	3-14
3.6	Hydrogen Transfer	3-17
3.7	Fuel Performance	3-18
3.8	Plant Water Inventory	3-21
3.9	Steam Generator Level Indication	3-23
3.10	References	3-24
4.0	OPERATOR RESPONSE	4-1
4.1	Procedures	4-1
4.2	Evaluation	4-2
4.2.1	Reactor Coolant Pump Operation	4-2
4.2.2	Verification of Natural Circulation	4-5
4.2.3	Safety Injection and Containment Isolation Reset	4-6
4.2.4	Restart of Charging Pumps	4-7
4.2.5	Isolation of B-SG Power Operated Relief Valve	4-8
4.2.6	Operation of Pressurizer Power Operated Relief Valve	4-8
4.2.7	Safety Injection Termination	4-10
4.2.8	Isolation of Condenser	4-11
4.2.9	Pressure Control	4-13
4.2.10	Isolation of B-Steam Generator	4-13
4.2.11	Cooling of B-Steam Generator	4-14
4.2.12	Lack of Procedural Coverage for SGTR and Failed SG Safety or Relief Valve	4-15
4.2.13	Termination of Letdown Relief	4-15
4.2.14	Indicator Lights Burned Out	4-16
4.2.15	Terminology Problems on Control Panels and in Procedures	4-17
4.2.16	Simulator Training	4-18
4.2.17	Procedures Deviations	4-18
4.3	Conclusions	4-20
4.4	References	4-21

TABLE OF CONTENTS (continued)

		Page
5.0	STEAM GENERATOR INSPECTION PROGRAM, FAILURE ANALYSIS, AND REPAIRS	5-1
5.1	Summary	5-1
5.2	Steam Generator Design, Surveillance, and Operating History	5-2
5.2.1	Steam Generator Design	5-2
5.2.2	Secondary Side Modifications	5-3
5.2.3	Steam Generator Operating Environment	5-4
5.2.4	Steam Generator Surveillance And Repair Requirements	5-5
5.2.4.1	Inservice Inspection Requirements for Steam Generator Tubing	5-6
5.2.4.2	Plugging Limits	5-7
5.2.4.3	Sleeve Repairs	5-8
5.2.4.4	Primary-to-Secondary Leakage Rate Limits	5-8
5.2.5	History of Tube Degradation Problems at Ginna	5-9
5.3	Steam Generator Inspections Following Rupture Occurrence	5-12
5.3.1	Eddy Current Inspections	5-12
5.3.2	Fiber Optic And Television Inspections	5-16
5.4	Failure Analysis	5-20
5.4.1	Introduction	5-20
5.4.2	Postulated Failure Mechanism-Summary	5-20
5.4.3	Eddy Current Data Review	5-21
5.4.4	Metallurgical Examination of Steam Generator Tubes	5-26
5.4.5	Analytical Assessment of Failure	5-30
5.4.6	Model and Laboratory Testing	5-39
5.5	Steam Generator Repair Program	5-41
5.5.1	Tube Removal	5-41
5.5.2	Loose Parts Removal	5-44
5.5.3	Mechanical Plug Removal	5-44
5.5.4	Material Accountability for Steam Generator Modifications	5-44
5.5.5	Post Repair Inspections and Modifications	5-48
5.5.6	Loose Parts Monitoring System	5-48
5.5.7	Intermediate Outage	5-49
5.5.8	Technical Justification for Repair Program	5-50

TABLE OF CONTENTS (continued)

		Page
5.6	Summary of Findings	5-57
5.7	References	5-62
6.0	EQUIPMENT DESCRIPTION, OPERATION, AND EVALUATION	6-1
6.1	Pressurizer Power Operated Relief Valves	6-1
6.2	Pressurizer PORV Block Valves	6-7
6.3	B-Main Steam System	6-7
6.4	Letdown Isolation	6-15
6.5	Effluent Radioactivity Monitoring System	6-17
6.6	Sump A Level Indication	6-20
6.7	Safety Injection Pump IC Auto Transfer Scheme	6-21
6.8	Use of Non-Safety Equipment	6-23
6.9	Process Computer	6-24
6.10	Subcooling Meter	6-26
6.11	References	6-28
7.0	EMERGENCY PREPAREDNESS/NOTIFICATIONS	7-1
8.0	RADIOLOGICAL ASSESSMENT	8-1
8.1	Mitigation of Radiological Consequences	8-1
8.2	Releases from the Unaffected Steam Generator	8-5
8.3	Survey Teams	8-5
8.4	Sampling	8-6
8.4.1	Air Sampling	8-6
8.4.2	Snow Sampling	8-7
8.4.3	Water Sampling	8-8
8.5	TLD Measurements	8-8
8.6	Estimated Offsite Doses	8-9
8.7	Ventilation Intake During SGTR Releases	8-10
8.8	Summary of Recommendations	8-10
8.9	References	8-11
9.0	Commitments	9-1
10.0	Summary of Findings	10-1
11.0	Environmental Consideration	11-1
12.0	Conclusions	12-1
13.0	Acknowledgements	13-1
Appendix A		
Appendix B		
Appendix C		

LIST OF FIGURES

Figure		Page
2.1	Schematic Diagram of Westinghouse-design pressurized water reactor of Rochester Gas & Electric Corporation Ginna Nuclear Power Plant	2-7
2.2	Reactor Coolant & S/G Parameters, January 25, 1982	2-8
2.3	Ginna B Steam Generator hot-leg tube sheet map before event of January 25, 1982	2-8
	Simplified reactor coolant system over pressure protection system (use 6.1-1)	2-9
2.4	Cooldown curves used for fracture mechanics analyses	2-10
3.1	System Data - Pressure Versus Time	3-26
3.2	System Data - Temperature Versus Time	3-27
3.3	Base Case - Reverse Flow Due to Break only	3-28
3.4	Case 1 - Forward Nat. Circ. Flow Minus Break Flow	3-29
3.5	Calculated Loop Flow and HPI & CC Flow Comparison	3-30
3.6	Cooldown Curves Used For Fracture Mechanics Analyses	3-31
3.7	Ginna Nuclear Power Plant Steam generator	3-32
4.1	Power Operated Relief Valve Control and Display-Old Relationship	4-22
4.2	Power Operated Relief Valve Control and Display-New Relationship	4-23
5.1	Westinghouse Model 44 Steam Generator	5-64
5.2	Schematic of B Steam Generator Tube Sheet Area	5-65
5.3	Ginna A steam generator hot-leg tube sheet map before event of January 25, 1982	5-66
5.4	Ginna B steam generator hot-leg tube sheet map before event of January 25, 1982	5-67

LIST OF FIGURES (Continued)

		Page
5.5	Ginna B steam generator hot-leg tube sheet map as of February 9, 1982	5-68
5.6	Ruptured Tube - R42 C55	5-69
5.7	Large foreign object removed from hot leg of B steam generator (1/2 in. thick)	5-70
5.8	Postulated Failure Mechanism Sequence	5-71
5.9	S/G Loose Parts Monitor Sensor Locations	5-72
6.1	Primary Diagram	6-29
6.2	Simplified reactor coolant System Overpressure Protection System	6-30
6.3	Pressurizer PORV	6-31
6.4	ASCO three-way Diaphram Solenoid Value	6-32
6.5	Flow Diagram of Main and Reheat Steam System	6-33
6.6	Steam Generator ASME Code Safety Valve	6-34
6.7	Chemical and Volume Control System	6-35
6.8	Diagram of Letdown line Isolation and relief Valves	6-36
6.9	Pathways for the release of radionuclides to the environment from the Ginna Steam Generator Tube rupture on January 25, 1982	6-37
6.10	Containment Sump A	6-38

LIST OF TABLES

Table		Page
3.1-1	Comparison of FSAR SGTR analysis to actual event.....	3-4
5.2-1	Ginna Station A Steam Generator Tube Plugging History.....	5-10
5.2-2	Ginna Station B Steam Generator Tube Plugging History.....	5-11
5.3-1	Results of TV Optics Examination in the B Steam Generator....	5-18
5.4-1	Sequences of Plugging in Periphery of B S/a.....	5-24
5.5-1	Plugged Tubes in Periphery by Category.....	5-43

1.0 INTRODUCTION

At 9:25 am on January 25, 1982, the R. E. Ginna Nuclear Power Plant experienced a tube failure in the B steam generator. Prior to the transient, the plant was operating at full power with no primary to secondary leakage. The plant transient resulting from the tube failure included a significant primary system depressurization, actuation of the safety injection system, and minor releases of radioactive materials from the plant. By letter, dated February 24, 1982, from D. G. Eisenhut (NRC) to John E. Maier (RG&E), RG&E was required to provide a written evaluation of the event for review and approval by the NRC prior to the restart of Ginna.

Rochester Gas and Electric Corporation has performed extensive evaluations of the tube failure event. The evaluations were submitted in two separate volumes by letters dated April 13, 1982 and April 26, 1982, and supplemented by letters dated April 23, 26 (3 letters), May 5, 6, 17 (2 letters), 18 and 21, 1982. The first submittal covers the sequence of events, reviews operator actions including plant procedures, discusses performance of selected equipment, presents results of analyses including a radiological assessment and provides recommendations for future actions. The second volume covers the steam generator inspection, evaluation, and repair program.

Shortly after the incident, Chairman Palladino requested that an NRC task force be established to report the circumstances surrounding the tube failure event. The task force has documented its findings in NUREG-0909 (NRC Report on the January 25, 1982, Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant). NUREG-0909 describes the factual information and significant findings associated with the event.

The purpose of this Safety Evaluation Report is to determine if the R. E. Ginna Nuclear Power Plant is safe to return to full power operations. To do this the staff has reviewed the licensees submittals along with the information

provided in NUREG-0909. We have organized this report to cover the items addressed by the licensee plus the significant findings of the Task Force as presented to the Commissioners on April 17, 1982. Also addressed are the applicable questions that were raised by the Commissioners during the briefing.

This report is comprised of 7 major sections. The first, Section 2, is a background and summary of the Safety Evaluation Report. Section 3 contains a comparison of the January 25, 1982, event with the Facility Description and Safety Analysis plus other analyses the licensee and the NRC staff have performed in regards to the event. Section 4 deals with the response of the operators to the event and the procedures which they used. The next two sections cover equipment performance during the event, with the steam generator evaluation contained in Chapter 5. Section 7 discusses the licensee's Emergency Preparedness Plan. The final major section is an assessment of the radiological aspects of the event.

2.0 BACKGROUND/SUMMARY

2.1 Background

The Ginna plant is a two-loop pressurized water reactor designed to produce 470 megawatts of electricity (See Figure 2.1). Each of the two reactor coolant loops contains a steam generator, a pump, loop piping and instrumentation. Pressure in the system is controlled by the pressurizer, where water and steam pressure is maintained through the use of electrical heaters and sprays.

The heat generated in the reactor is removed from the core by the reactor coolant (water) and transported to the steam generators. The steam generators transfer the heat, from the primary coolant passing through the U-tubes, to the water in the secondary side of the steam generator, causing the secondary water to boil. The primary coolant, after giving up its heat, is returned to the reactor vessel where it will again be heated.

The steam generated in the steam generator then flows via the main steam lines, to the turbine-generator where the electricity is produced. The exhaust from the main turbine is condensed and then pumped through the feedwater heaters back to the steam generator where it will again be turned into steam as it repeats the above cycle.

On January 25, 1982, one of the 3,260 steam generator tubes in the B-steam generator ruptured. There was no indication of primary to secondary leakage prior to the rupture. The plant transient resulting from the tube failure included a significant primary system despressurization, actuation of the safety injection system, and a minor release of radioactive matèrials from the plant. Figure 2.2 provides a graphic representation of the reactor coolant system and steam generator parameters during the early phases of this event.

In the course of mitigating and recovering from the tube rupture event, a number of problems occurred with equipment and procedures that made the

recovery more difficult. The Rochester Gas and Electric Corp. has evaluated each of these major areas, plus other related matters, and has submitted their evaluation for the NRC's review. The NRC staff and their consultants have reviewed the licensee's submittals, and have performed independent analyses in order to determine if it is safe for the Ginna plant to return to power operations.

2.2 Summary of Major Issues and Findings

The staff has completed its review of the tube rupture and related events and the licensee actions taken subsequent to January 25, 1982. Based on meetings and discussions with the licensee and its consultants, and based on the repairs, modifications and changes made to the facility and procedures along with the commitments made for future actions, the staff has concluded that the facility can be safely operated with no undue risk to the public health and safety. A brief discussion of the major issues related to the event is provided below. The detailed staff evaluations are provided in subsequent chapters.

2.2.1 Steam Generator Tube Rupture

Investigations performed subsequent to the steam generator tube failure on January 25, 1982 revealed the immediate cause of the failure to be excessive thinning of the tube wall leading to a pressure burst of the tube. The ruptured tube was located in the hot leg of B-steam generator, three rows inboard of the tube bundle periphery (see Figure 2.3). Numerous tubes in the peripheral region, including the outer two rows of tubes immediately adjacent to the tube which ruptured, had been plugged previously (beginning in 1976) as a result of indications of degradation during routine inservice inspections of these tubes or as the result of small primary-to-secondary leaks.

Visual inspections using television techniques have revealed extensive damage to previously plugged tubes in the peripheral area. Numerous foreign objects and pieces of broken steam generator tubing have been found in the annular region between the tube bundle and the shell. The foreign objects are believed by the licensee to have been introduced during steam generator modifications performed in 1975. The largest foreign object acting

in conjunction with normal thermal and hydraulic loadings is postulated to have initiated a sequence of events which led to the plugging of many tubes at or near the periphery, and eventually to the tube rupture. The wall thinning which led to the rupture is postulated to have occurred as a result of contact wear with an adjacent tube which had previously been plugged and which was subsequently severed at the lower end.

The licensee and the staff have performed comprehensive investigations of the extent of tube degradation in the Ginna steam generator and the potential failure mechanism. Based upon the results of this investigation, the licensee completed a number of activities to eliminate the conditions which caused the failure. These include the removal from the steam generators of all foreign objects along with sections of previously plugged tubes that are sufficiently degraded and could potentially cause degradation of adjacent tubes.

The staff has concluded, based on independent evaluations, that the scenario postulated by the licensee is the most likely cause of tube failure and that the actions taken or planned by the licensee provide reasonable assurance that the postulated conditions for future tube failures have been eliminated.

2.2.2 Pressurizer Power Operated Relief Valve (PORV)

Overpressure protection for the pressurizer and the reactor coolant system is provided by the PORVs and the pressurizer safety valves. The PORVs prevent opening of the safety valves for mild pressure transients and can be manually opened from the control room. The motor-operated block valve upstream of the PORV provides a means of isolating a stuck-open or leaking PORV (see Figure 2.1).

During the event one of the PORVs was opened to reduce the reactor coolant (primary) system pressure. This was done to reduce the amount of slightly radioactive reactor coolant leaking to the secondary side of the steam generator.

A large differential pressure between the primary and secondary systems will cause more reactor coolant to leak through the tube rupture and can lead to the release of radioactive materials should the secondary side relief valves lift. Following the fourth opening of the PORV over a period of 2 minutes, and after receiving a signal to close, the PORV began to close and then returned to the full open position. The PORV block valve was then manually closed to prevent further depressurization of the reactor coolant system.

After extensive investigations as to the cause of the PORV failure the licensee has concluded that an alternation made in 1979 to the PORV control air system had been responsible for the PORV failing to close. The alteration had been made by the licensee to reduce the closure time of the PORV in order to extend the total valve cycle time during any low temperature-overpressure transient. The alteration (restriction of the exhause line) was inconsistent with the valve manufacturers installation and maintenance instructions.

In order to preclude future problems the licensee has modified the piping between the solenoid valve and the PORV in accordance with the manufacturers recommendation. This modification allows full flow to open the PORV along with reduced closure time. The staff concurs with the licensee's modification and has concluded that future performance of the PORV will be acceptable.

2.2.3 Procedures

Following the steam generator tube rupture (SGTR) event, multiple control room alarms alerted the operator to a reactor coolant system (RCS) rapid depressurization. The air ejector radiation monitor alarm indicated the existence of a steam generator tube rupture and the continuing reactor coolant system pressure drop resulted in an automatic reactor trip and automatic actuation of all three safety injection pumps. The safety injection actuation further caused an automatic containment isolation and tripped the charging pumps. Various procedures were used by plant personnel following the automatic safety injection initiation to diagnose and track the course of the event and to complete the immediate actions required.

The staff position is that where operations are covered by procedures, the prescribed actions are expected to be followed. When the event deviates from expectations, a reasoned and considered approach to cope with the contingency should be developed. It is expected that the method developed will be presented to licensee management and authorization for the prescribed actions will be obtained, unless immediate action is required to protect the health and safety of the public. The emergency procedures covering the event were used early in the event and, in general, were followed step-by-step. The staff has identified that some deviations from the approved procedures were made. The operators were receiving instructions through their supervisors from the Technical Support Center, which has the authority, when several of the individual present there assemble as the Plant Operation Review Committee, to change procedures and authorize their use.

The staff evaluation has determined that the operators' response and the written procedures invoked for mitigation of the event, to a large degree were consistent with the predicted and accepted guidelines on which operator training and procedures were based. The significant deviations from the procedures, by plant personnel, were consciously made following a study of their consequences before execution. Subsequent review of the deviations by the licensee has resulted in short term procedure modifications and a commitment by the licensee to perform further analyses to determine any long term modifications that are needed.

Based on the licensees response to the event and the program for further improvements, the staff has concluded that adequate protection is provided for future steam generator tube rupture events, should they occur.

2.2.4 Thermal Transient on the Reactor Coolant System

Following the event the licensee performed an evaluation to determine if the pressure and temperature transients that were imposed on the reactor vessel could have led to significant pressurized thermal shock of the vessel welds. The licensee concluded that thermal shock was not a problem during this event.

The reactor vessel welds are susceptible to neutron embrittlement due to their close proximity to the core. If the welds were to become sufficiently embrittled then a combination of cold temperature and high pressure over a period of time could initiate cracks in the vessel welds.

The licensee and the NRC staff have independently reviewed the pertinent data to determine if there is a concern with pressurized thermal shock as a result of the steam generator tube rupture. The data reviewed supports the Task Force findings that there was reverse flow in the B-loop during the period of the large temperature drop. This reverse flow pattern reasonably accounts for the temperature sensor readings and indicates that the cold water was flowing away from the reactor vessel during the large temperature decrease. This would indicate that the reactor vessel would have never experienced temperatures below the indicated temperature of the A-loop cold leg.

However, conservative fracture mechanics analyses were performed assuming the downcomer did cool down as indicated by the measured B-loop temperature. Two cases were studied (see Figure 2.4). The worst case, Case 2, bounds the data. This analysis indicated that no crack initiation occured at Ginna. A conservative value for the RT_{NDT} (nil-ductility transition reference temperature) of 225°F was used. The total stress intensity factor calculated by combining the effects of thermal stress, pressure stress and that due to the cladding peaked at less than 75 Ksi-in. The critical value of fracture toughness never got below 100 Ksi-in. Therefore the staff concludes that pressurized thermal shock of the Ginna reactor vessel was not a concern due to the SGTR transient.

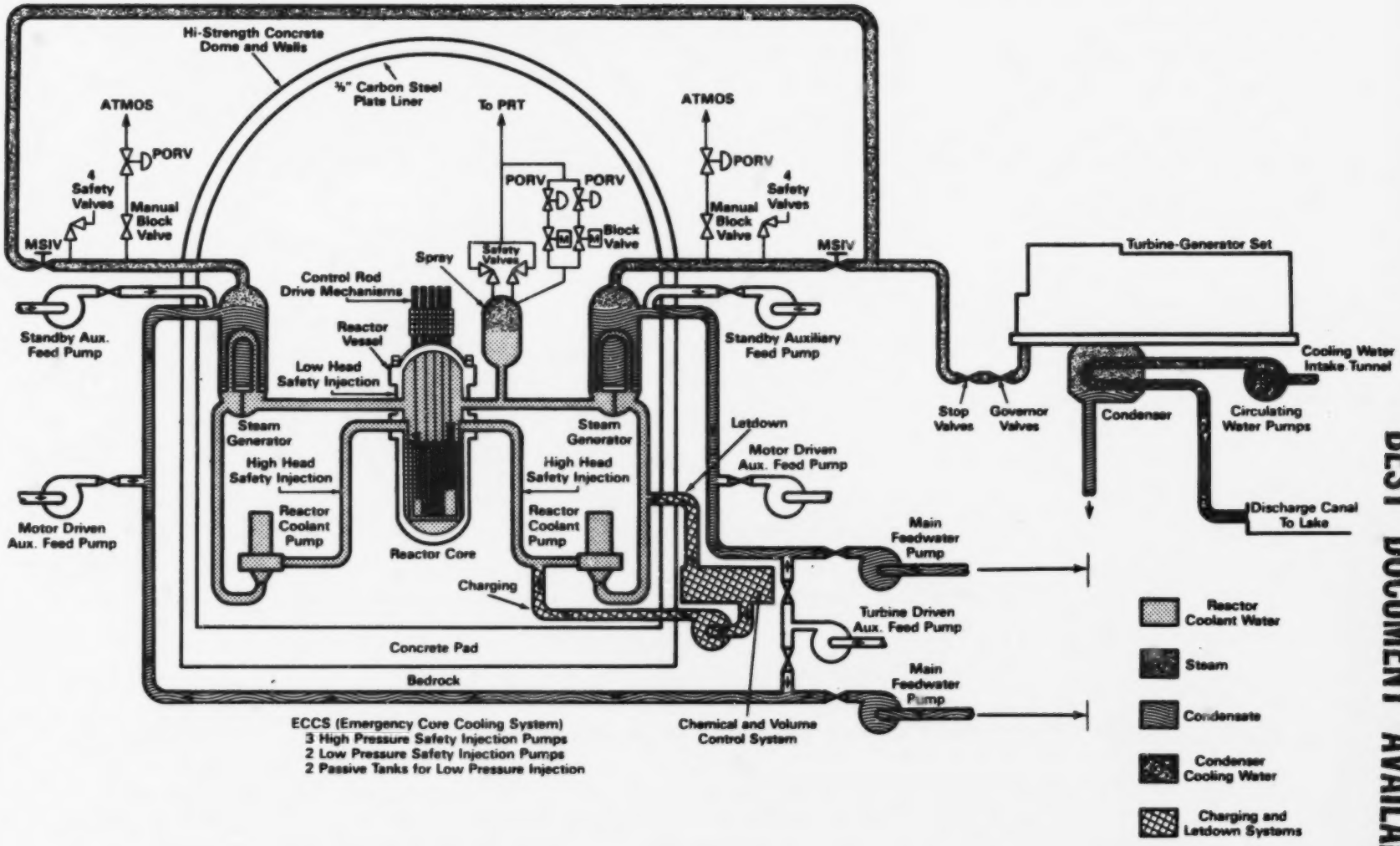
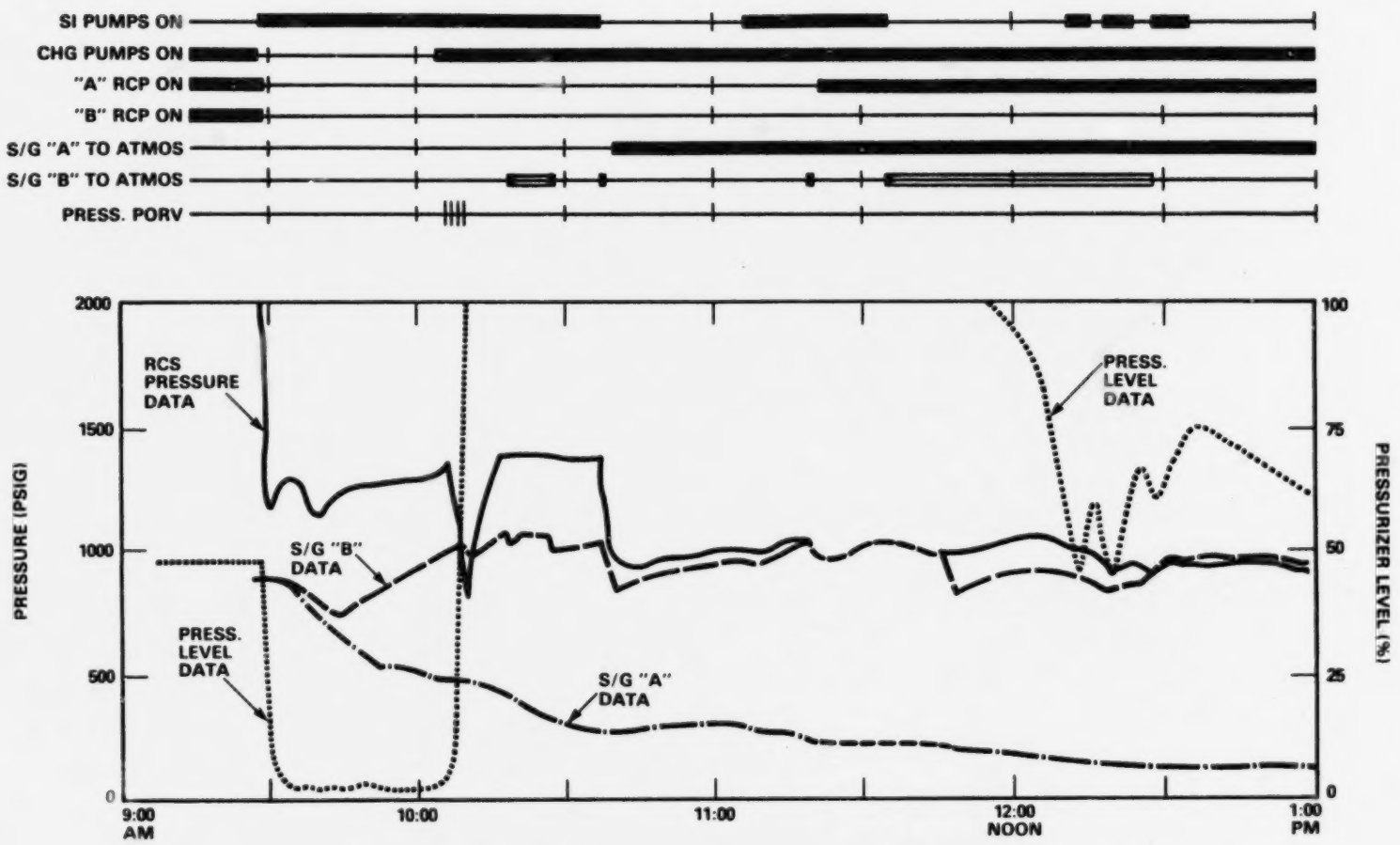


Figure 2.1 **Schematic diagram of Westinghouse-designed pressurized water reactor of Rochester Gas & Electric Corporation's Ginna Nuclear Power Plant**

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE



REACTOR COOLANT AND STEAM GENERATOR PARAMETERS AS A FUNCTION OF TIME, JANUARY 25, 1982 GINNA NUCLEAR POWER PLANT

Figure 2.2

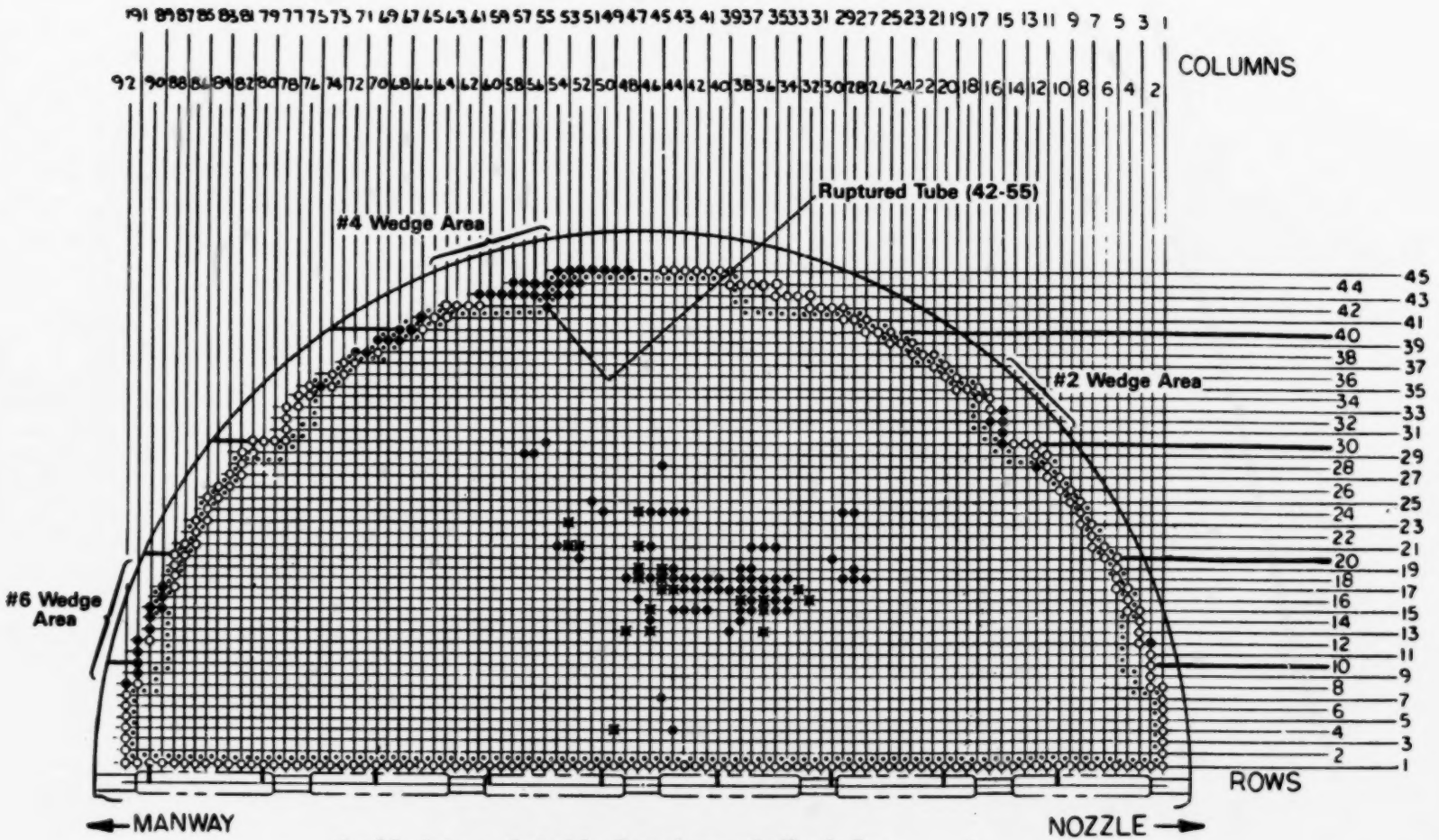


Figure 2.3: **Ginna B steam generator hot-leg tube sheet map before event of January 25, 1982**

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

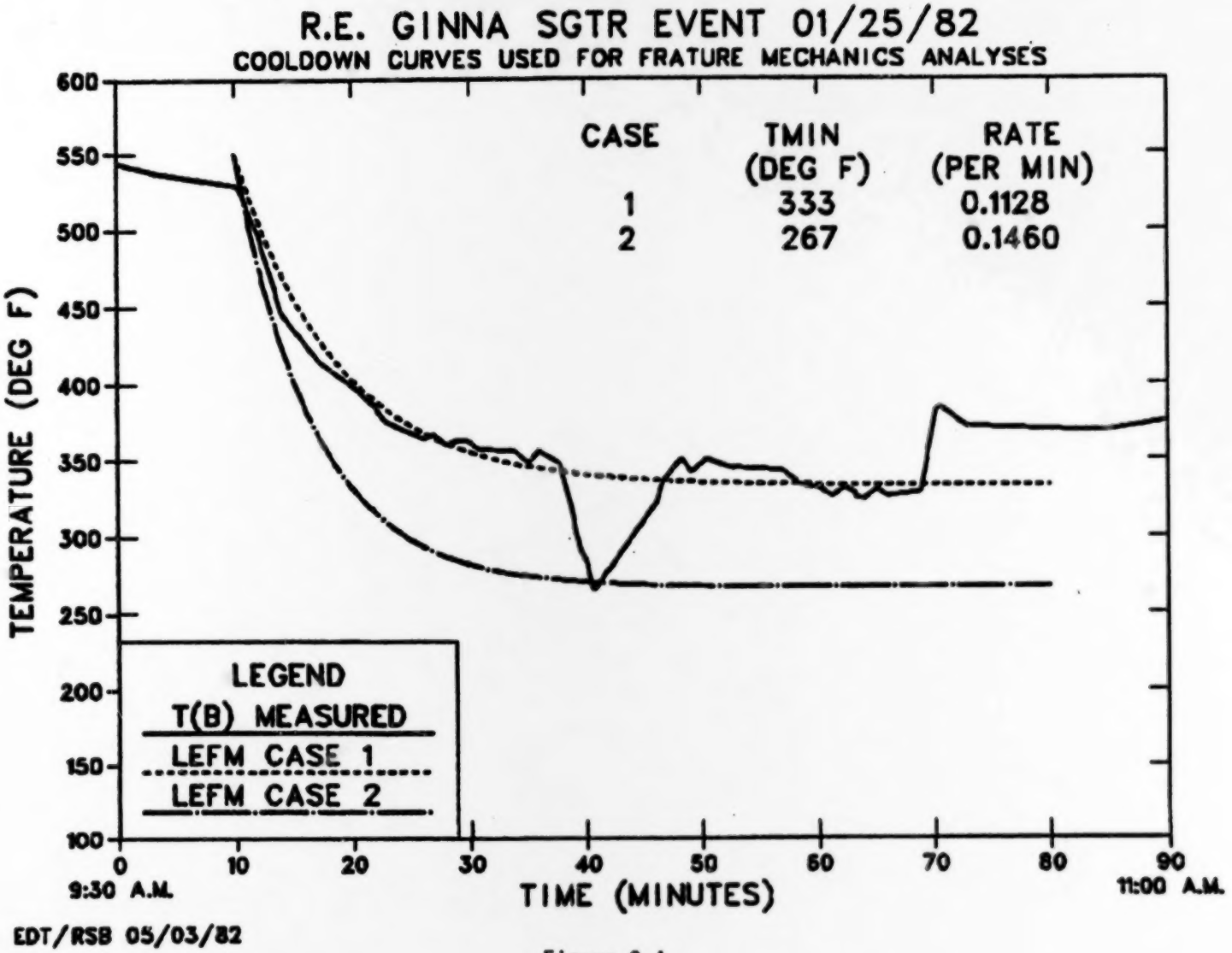


Figure 2.4

3.0 TRANSIENT ANALYSES

3.1 Comparison of Plant Response with Previous Analyses

The purpose of this discussion is to compare the actual plant systems response, operator actions, and offsite consequences during the January 25, 1982, Ginna steam generator tube rupture event to the assumptions and predictions of previous Facility Description and Safety Analysis (FDSA) (Ref. 1) or other licensing SGTR analyses. The comparisons are made to determine if the actual event was suitably bounded by the reference safety analyses, and to determine if the safety analyses adequately predicted the course of the event, keeping in mind that conservative assumptions made for licensing calculations bias the predictions in a conservative direction.

This section is not intended to evaluate the operator actions or plant systems response in the actual event, nor is it intended to evaluate the procedural adequacy. Neither is it intended to evaluate the offsite consequences. These analyses are described in other sections.

3.1.1 Reference Analyses

The Ginna FDSA Steam Generator Tube Rupture (SGTR) analysis evaluated two cases both assuming the main condenser remains available throughout the event and an additional bounding calculation assuming the entire RCS contents, including the iodine from one percent failed fuel, were released directly to the environment. In the first case, the analysis assumes the operators isolate the affected SG one hour after the event. Isolation requires the main steam isolation valve (MSIV) be closed, feed flow (both main and auxiliary) be stopped, the atmospheric relief valve (ARV) on the damaged generator be blocked, and the RCS pressure be reduced to below 1100 psig to stop the primary-to-secondary leakage through the damaged tube. The mass flow into the secondary system and steam dump into the condenser will terminate in one hour. It was concluded that "the whole body I-131 dose at the site boundary is less than 0.27 rem."

In the second case, the FDSA assumed that the SG was not isolated for 4 1/2 hrs and all of the reactor coolant activity is transferred to the steam system and the condenser. The whole body dose in this case is predicted to be 1.04 rem.

The FDSA predicts that with a single tube rupture and steam dump to the condenser available, the steam generators (damaged and intact) safety valves will not lift. Without the main condenser, the safety valves(s) of the damaged SG may lift. Even though the FDSA predicts no failed fuel in the above two analyses, the offsite consequences as a result of the condenser being unavailable case are evaluated assuming one percent failed fuel. These results are less than the 10 CFR 100 limits.

3.1.2 Plant Systems & Operator Actions Comparisons

This section compares the FDSA assumptions, predictions and analyses to the actual events (Refer to Table 3.1-1.)

3.1.2.1 Reactor Trip and Safety Injection Actuation

The FDSA assumed a reactor trip on low pressurizer pressure and low pressurizer level. However, the plant no longer has a low pressurizer level reactor trip as a result of changes made after the TMI accident. The reactor tripped on low pressurizer pressure 3 minutes after the tube rupture. The safety injection system was actuated on low pressurizer pressure slightly after the reactor trip, as predicted in the FDSA.

3.1.2.2 Air Ejector High Radiation Alarm

If offsite and onsite power is retained, the FDSA predicts that the air ejector radiation monitors will alarm early indicating the passage of primary fluid into the secondary system. In the actual event, the air ejector high radiation alarm occurred within a minute of the SGTR and was the first indication of a SGTR.

3.1.2.3 Reactor Coolant Pump Trip

The FDSA did not assume or predict manual or automatic tripping of the reactor coolant pump during the course of the event, however, all RCPs were manually tripped about 1 minute after the low pressurizer pressure safety injection signal was actuated.

This action is in accordance with requirements for all PWRs as a result of studies made since the TMI accident, and is incorporated in the plant procedures and training (See Section 4.2.1). However, the FDSA analysis of systems performance during a SGTR does not assume this action. Since the RCS flow, temperature distribution and pressure is strongly affected by the lack of forced RCS flow, the FDSA analysis of the RCS and other systems performance can not be concluded to bound the actual plant performance. It should be noted that recent analyses performed by the Westinghouse owners group to support the emergency operating guidelines for SGTR address the affects of RCP trip. Nonetheless, the reference safety analysis does not.

3.1.2.4 Turbine Trip and Steam Bypass

The FDSA predicts that a reactor trip would automatically trip the turbine and steam bypass to the condenser would be initiated until RCS temperature reached a predetermined value. During the event, the generator/turbine trip and subsequent steam bypass occurred, as predicted.

3.1.2.5 Plant Cooldown

With respect to the plant cooldown following the scram and safety injection, the plant behavior was very much the same as predicted in the FDSA except for the PORV failure, the void formation in the RCS and the RCS pressure. The following four items are specifically addressed in the FDSA.

1. Boration of the RCS by the high head safety injection pumps occurred, as predicted, following Safety Injection initiation. However, later in the event, when RCS pressure was reduced below the damaged SG pressure, slight

BEST DOCUMENT AVAILABLE

Table 3.1-1 Comparison of FSAR SGTR analysis to actual event

Item	FSAR prediction (or assumed time)	Actual event	DID FSAR Bound Actual Event
Reactor Trip (low Lp + low Pp)	yes	3 min	yes
SIAS (low Pp)	yes	3 min	yes
Alarm of air ejector	yes	0 min	yes
RCP manual trip	no	4 min	no
Turbine trip on Reactor Trip	yes	3 min	yes
Bypass steam to condenser	yes	B SG - 15 min. A SG - 70 min.	yes
Plant Cooldown			
a. Boration w/ HHSIP	yes	start at 3 min	no[1]
b. Control Lp w/ spray or PORV	yes	no	yes
c. Throttle HHSI flow to lower RCS pressure	yes	1 hour 10 min	yes
d. Dump steam to condenser or atmosphere (from undamaged SG)	yes	throughout the event	yes
Void formation in RCS	no	42 min	no
Isolation of damaged SG			
a. Drop RCS pressure 1100#	(1 - 4 1/2 hours)	1 hour 40 min[2]	yes
b. Shut MSIV	(1 - 4 1/2 hours)	15 min	yes
c. Block ARV	(1 - 4 1/2 hours)	28 min	yes
d. Stop feed (MFW & AFW)	(1 - 4 1/2 hours)	21 min	yes
Operation of damaged SG SV	yes	yes	no[3]
Primary-to-secondary leak rate	800 gpm	760 gpm	yes
Filling damaged SG steam lines	no	yes	no

[1]Boration occured, as predicted, but it is not apparent that the FDSA predicted the RCS dilution later in the event as the broken SG contents flow back into the RCS.

[2]The RCS pressure was below the SG SV setpoint (1100#) after 2 hours 10 min. However, leakage into the damaged SG continued beyond this time until approximately 3 hours due to the reduced damage SG pressure from the leaking SV.

[3]FSAR says the damaged SG SV may lift if the condenser is not available. The SG SV did lift, but apparently failed to properly close.

dilution of the RCS occurred as the feed water (with dilute RCS fluid) flowed back into the RCS. Dilution was never specifically addressed in the FDSA.

2. The FDSA assumed the control of the pressurizer level with normal spray or relief valves. In the actual event, the safety injection system was used to control the pressurizer level since the RCPs were tripped.

3. The FDSA predicted operators would throttle safety injection flow to reduce reactor coolant pressure to several hundred psi subcooling. The operator opened the pressurizer PORV to control system pressure. However, the PORV did not perform properly. During its fourth operation, the valve stuck necessitating closure of the upstream block valve. This performance and the associated RCS pressure drop was not assumed in the FDSA analysis. The FDSA contains no specific evaluation of RCS pressure so a comparison of the actual event to the FDSA can not be made. However, it is likely that the FDSA analysis did not assume continued operation of the High Head Safety Injection Pumps and maintaining RCS pressure as high as it was. As described in Section 4.1, the operators were apparently concerned about void formation in the RCS and kept the safety injection flow high and, consequently, pressure high. The continued in-leakage into the damaged steam generator is discussed below.

4. The FDSA assumes either blowdown of the good SG to the condenser or atmospheric relief, the latter actually occurred.

3.1.2.6 Void Formation

In the course of manually opening of the pressurizer PORV to lower RCS pressure, a rapid rise in pressurizer level indicated that a void had been formed in the RCS. There were no predictions or analyses in the FDSA of any void formation in the course of the SGTR or recovery, therefore, since system response could be significantly different with a void, the FDSA can not be concluded to bound the actual plant performance in this respect.

3.1.2.7 Isolation of Damaged SG

The FDSA assumed isolation of the damaged steam generator at one hour, or four and one half hours. The plant behavior in these cases, however, did not assume SG overfill as discussed in the following:

1. The FDSA assumed reducing safety injection flow to drop the RCS pressure to below 1100 psi at either one hour or four and one-half hours. In the actual event, plant pressure fluctuated above 1100 psia until two hours and 10 minutes after the tube rupture when it was bought to 1100 psig. This resulted in lifting the damaged steam generator safety valves a number of times. Even after RCS pressure was bought to below 1100 psia, leakage continued into the steam generator since the damaged steam generator pressure also dropped, probably the result of the leaking steam generator safety valve. Leakage into B SG continued until about three hours after the event. The continued leakage into B SG, resulted in excessive level and concern regarding the steam line ability to withstand the extra weight of being filled with water.

   Since the FDSA assumed time for primary and secondary pressure equilization did not result in SG overfill, and the FDSA did not analyze the resulting system (as well as offsite consequences - Section 8.1.3) effects, the FDSA does not bound the actual event in this respect.

2. The FDSA assumed the closure of the damaged SG MSIV and blocking the atmospheric relief in either one or four and one-half hours. The plant actually isolated the B SG MSIV and blocked the atmospheric relief valves 15 minutes and 28 minutes respectively, after the event.

3. The FDSA assumes that all feedwater flow to the faulty SG is rapidly stopped. In the actual event, all feedwater was isolated after about 21 minutes (Normal FW was isolated at 3 min. AFW at 21 min).

4. The FDSA states that either the condenser dump or atmospheric relief valves from the intact steam generator should be used to cooldown the

BEST DOCUMENT AVAILABLE

reactor. In the actual event the licensee secured the condensate system after an hour and 15 minutes to minimize the spread of radioactive contamination. Securing the condensate system was voluntary and made the main condenser unavailable for further dumping of steam. The licensee manually opened the "A" steam generator ARV to continue the plant cooldown and remove decay heat.

Since this is discussed and assumed in the FDSA, the actual plant performance is considered bounded by the FDSA analysis.

3.1.2.8 Operation of Damaged Steam Generator Safety Valve

The FDSA states that lifting of damaged or intact steam generator safety valves is possible if the condenser is not available for heat removal. In the actual event, the damaged B steam generator safety valve lifted five times. After the last operation, the safety valve apparently failed to fully close. This failure was not explicitly considered in the FDSA, nor was its effect on continued primary-to-secondary leakage. This is further discussed in Section 3.1.3.

3.1.2.9 Primary to Secondary Leak Rate

The FDSA predicted that with a double ended guillotine break of a single steam generator tube, the primary to secondary leak rate would be about 843 gpm. The initial leak rate at Ginna was calculated to be about 760 gpm, even though the break was not a double ended guillotine break.

3.1.2.10 Damaged SG Overfill

The FDSA did not analyze the consequences on overall system performance due to filling of the damaged SG up to the steam lines as apparently actually occurred. This caused water release out the SG safety valve, and a concern that the steam lines would not be able to withstand the extra weight from the accumulated leakage. Water release is also a concern from a radiological standpoint, as is discussed in Section 8.1.3.

3.1.2.11 Summary

Overall, since the FDSA bounding analysis determined the consequences of the release of the entire RCS volume directly to atmosphere and only approximately one-half of the RCS volume was leaked to the damaged steam generator, it is concluded that the FDSA analysis of the integrated leakage from the RCS bounds the actual leakage experience during the Ginna event. However, the FDSA analysis did not include the following important system effects that were experienced during the actual event; tripping of all RCPs, void formation in the RCS during depressurization, and continued leakage into the damaged steam generator due to continued safety injection pump operation and the leaking B SG safety valve. It should be noted that analyses in support of the proposed emergency operator guidelines analyzed the effects of RCP trip, but not RCS void formation or continued leakage into the damaged steam generator. Nonetheless, we consider the effects of RCS void formation to be small as long as the RCS cooldown and depressurization continues. The effects of flooding the steam generator and steam lines due to continued in-leakage should be evaluated since damage to the steam line and maloperation of the safety valve(s) may be experienced. Should the steam line break as a result of the weight of water in the lines, excessive releases may result.

The radiological consequences of two phase or water flow out the damaged SG safety valve should also be considered. Since the tripping of the RCPs played a significant role in the overall event, and probably resulted in the operator's decision to continue safety injection which caused the SG overfill, the FDSA is nonconservative with respect to SG level and should be reanalyzed. The analyses required in Section 4.2.1 and 8.2 will address this concern.

3.1.3 Comparison of the Radiological Calculations in the FDSA With the January 25, 1982 Accident At Ginna

The emphasis in the licensee's FDSA analysis is on releases from the condenser. If the condenser is used to mitigate the radiological consequences of an SGTR accident, and there are no releases save condenser releases, the offsite dose consequences are expected to be very small. This is because the condenser is

efficient at retaining iodine, and little is released out the steam jet air ejector (as discussed in the FDSA page 15.2.4-4). Noble gases are released, but the dose consequences from them are small for this type of accident.

The staff's design-basis SGTR analyses presently include the assumption that the condenser is unavailable, since there are a number of reasons it may be unavailable after an accident; loss of offsite power; loss of instrument air; loss of service water resulting in loss of instrument air; the turbine bypass valves being out of service; and, as during the Ginna accident, a decision to remove the condenser from use. Without the condenser as a heat sink, there will be steam or steam/water release from the unaffected steam generator (always), and from the affected steam generator (for essentially all design-basis accidents). In this event, considerably more radioiodine is released, and the dose consequences are dominated by the iodine releases. The licensee analyzed this type of accident, but the description of the analysis is too vague. The FDSA refers to "all the primary iodine activity expected from 1% failed fuel," without specifying how many curies would be expected to be released to the coolant. The description says this release, via the atmospheric relief or code safety valves, "could only occur if all offsite power to run the main condenser was lost and..." Since there were, in fact,considerable releases from the B steam generator code safety valve during the Ginna accident, even though offsite power was available, the staff concludes that the licensee underestimated the probability of releases from paths other than the condenser. Secondary leakage is prolonged beyond the time typically assumed by the licensee and by the staff. Because this prolonged leakage both increases the secondary side fission product (mostly iodine) concentration, and decreases the iodine partitioning, it is important to consider the effects of continued leakage into the SG and overfilling with liquid release out the SV.

In summary, the staff finds that most of the radiological consequences analysis in the FDSA focussed on non-conservative accident scenarios, and that there is too little information to evaluate the more conservative scenario.

3.2 Sequence of Events

The sequence of events presented in the licensee's April 12, 1982 report(Ref 32) has been reviewed to determine if it represents a sufficiently complete and accurate understanding of the January 25, 1982 event, to serve as the basis for determining what activities need to be undertaken before plant restart. The licensee's sequence of events has been compared to the sequence of events in the NRC Task Force Report on the January 25, 1982 Steam Generator Tube Rupture at R.E. Ginna Nuclear Power Plant, NUREG-0909 Ref 3.3. Both reports are generally in agreement. The licensee's report has considerably less detail than the NRC staff report but only disagrees on one specific point. Whereas the licensee's report states that the charging pumps (plural indicating more than one pump) were started at 10:04 a.m., the NRC staff report indicates that only one charging pump was restarted, based on the available computer output. The licensee's report states that this action was in accordance with procedure E-1.4 while the NRC staff report states that the action was a deviation from the procedure which calls for starting "all available charing pumps." The staff is continuing to evaluate the consequences of this issue.

This one difference does not detract from the usefulness of the licensee's sequence of events to serve as the bases for determining what activities need to be undertaken before plant restart. The licensee's sequence of events is therefore acceptable for this purpose. For completeness we list in Appendix C the sequence of events as it appeared in NUREG-0909.

3.3 Steam Void Formation

3.3.1 Background

Steam voids can form in part of the reactor coolant system any time the pressure falls below saturation for that part of the system. NUREG-0909 suggests this occurred twice, first during the initial sharp depressurization following reactor trip and then during the second sharp depressurization when the PORV stuck open. In addition, the licensee suggests a possible intermediate period

of void formation as the pressure dropped just prior to isolating the faulted steam generator (Ref. 3.2).

3.3.2 Evaluation

In the first few minutes after reactor trip, the pressure reached saturation in the upper head and in the pressurizer surge line indicating flashing occurred in those locations. This was almost the same time the reactor coolant pumps (RCP's) were tripped. In fact, termination of the depressurization was apparently due to reaching saturation in the upper head along with safety injection actuation. Unfortunately upper head thermocouple data was not available until more than twenty minutes into the event. Also, the thermocouples are all near the bottom of the upper head. Therefore, it is not known what the extent of void formation was during this time. However, no pressurizer insurge typical of significant void formation occurred at this time. In fact the level was dropping rapidly due to the tube rupture and system cooldown. When upper head thermocouple data again became available at 0948, temperatures were at least 10 degrees below saturation until the PORV stuck open at 1009 and the second big pressure decrease occurred. In addition, core exit and hot leg temperature were always subcooled indicating that core cooling was never a problem. It should be noted that tripping the RCPs had little to do with the initial flashing in the upper head since the pressure was already at or near saturation when the pumps were tripped.

Regarding the licensee's postulation of flashing prior to steam generator isolation, the data is unclear since available upper head thermocouple data is unavailable for this time and the pressurizer level was off-scale low.

When the PORV was operated and stuck open between 1007 and 1011, data was available and gave clear indication of void formation in the upper head. At 1008 the system pressure reached saturation in the upper head (1080 psia) and the upper head temperature dropped as flashing occurred. The rapid rise in pressurizer level, which accompained the pressure decrease, could not be accounted for without consideration of void formation in the upper head. However, it should be noted that there is considerable uncertainty associated

with estimating the magnitude of all contributions to the pressurizer level rise.

Westinghouse reactor systems are designed so that a small amount of flow is bypassed to the upper head when the RCPs are running. Also, some flow from the guide tubes is predicted to enter the upper head during forced circulation. When the RCPs were tripped, the upper head was effectively isolated from circulation cooling. During the entire event the fluid circulating through the core and the active steam generator was cooling down. By 1000, just prior to PORV actuation, the average core exit temperature was 500°F, down almost 100°F from steady state. Meanwhile, the upper head had cooled to only 555° and was cooling very slowly (~ 40°F/hr). From this rate is appears that most of the upper head cooling up until then was due to the flashing during the initial depressurization. It is certain that had the RCPs been running, the upper head temperature would have been much closer to the rest of the system temperature and would have mitigated some of the void formation during PORV operation. The effect of RCP operation was notable when one pump was restarted at 1120. The first subsequent reading of upper head temperature at about 1150 showed the bottom of the upper head to be virtually the same as the core exit temperature.

3.3.3 Conclusion

Despite formation of upper head voids it is most important to note that there was never any indication that the core was not subcooled. Thus, effective cooling was always maintained and the existence of the bubble in the upper head posed no threat of core uncovery or inadequate core cooling. However, the actual extent and timing of void formation and condensation remains unclear. The staff concludes that this is still an important issue. The licensee has agreed to perform, within six months, a detailed thermal-hydraulic computer analysis, of the reactor system behavior during the event, to verify the key thermal-hydraulic phenomena that may have taken place.

BEST DOCUMENT AVAILABLE

3.4 Calculation of Primary to Secondary Leak Rate

3.4.1 Background

The licensee's report (Ref. 3.2) estimates that the maximum leak rate was 601 gpm and occurred at 9:27 a.m., following an initially smaller leak rate of approximately 350 gpm. The NRC staff report, NUREG-0909 (Ref 3.3), estimates the maximum leak rate at 760 gpm and indicates that the leak rate reached a maximum value at 9:25:25 a.m. and decreased as the RCS pressure decreased. This compares to the leak rates for the Surry 2 and Prairie Island events of 330 gpm and 336 gpm. These values, which are staff estimates, appear in Table 3.8 of NUREG-0909 and Table 10 of NUREG-0651. The staff's analysis indicates that the variations in the rate-of-change of pressurizer pressure and level are due to the changes in RCS temperature and the increase in charging flow. It should be noted that neither the licensee's nor the staff's metallurgical analyses of the ruptured tube provide any evidence to support the postulation that the rupture developed in two stages.

3.4.2 Evaluation

One of the major uncertainties associated with the estimate of the maximum leak rate is the charging flow as a function of time. The initial charging flow is well known but the time at which the second and third charging pumps were started is not well known. Although the licensee's report indicates that additional analyses are continuing, it may not be possible to conclusively establish the leak rate to within 100 gpm (i.e., ~15%).

3.4.3 Conclusion

Both the licensee's and the staff's estimates for the maximum leak rate are below the FSAR assumed value of 843 gpm. Therefore the January 25, 1982 leak can be characterized as one which approached but did not exceed the FDSA design basis accident assumption. Neither the leak rate estimates nor the examination of the ruptured tube indicate that any changes are required in the plant's design basis.

3.5 Thermal Transient on Reactor Coolant System

3.5.1 Background

The Task Force analysis Ref 3.3 of the thermal-hydraulic conditions in the vessel using the data gathered from the available instrumentation could not preclude conditions of pressurized thermal shock (PTS) to the reactor vessel. This issue is addressed in Section 1.4.1, item 8 of NUREG-0909 Ref 13. However, review of the task force analysis and independent assessment supports the conclusion that vessel damage due to thermal shock is highly unlikely.

3.5.2 Evaluation

An independent analysis of the data supports the findings of the Task Force on reverse flow in the B-loop. This reverse flow pattern reasonably accounts for the temperature sensor readings, as discussed below. Figures 3.1 through 3.3 show the plant data and the results of this analysis. The analysis assumes the downcomer feeds the flow to the B-loop at a temperature near that of the A-loop (as measured by the A-loop temperature sensor; ~18 in. from the SI nozzle in the direction of the reactor coolant pump; curve C of Figure 3.3). The B-loop flow is calculated using the model provided by the Task Force. The resulting temperature in the B-loop (Curve B of Figure 3.3) compares favorably with the data, also shown in Figure 3.3 (Curve A).

The information provided by the Task Force and by Ginna Ref 3.4 has been reviewed to determine if other flow patterns could have existed in the B-loop. The B-loop steam generator appears to have been a heat source during the period of interest, i.e., between 9:50 and 10:30 a.m. This would account for the loss of natural circulation flow in the B-loop. Thus, the existence of natural circulation appears to be highly unlikely, as there was no indication of a high flow, cold temperature fluid entering the downcomer. An imbalance in the excore neutron readings or in the core exit thermocouple readings should have also provided additional evidence for natural circulation. If there was natural circulation and the B-loop temperature reading was not impacted by the SI flow, then the mixed temperature at the downcomer would be about 10°F less

BEST DOCUMENT AVAILABLE

than the measured value in the B-loop as shown in Figure 3.4. A report prepared by Creare Incorporated for EPRI on thermal mixing (Ref 3.5) has been reviewed to see if additional insight can be provided regarding the B-loop temperature readings. The EPRI thermal mixing study has identified a number of phenomena which can be utilized to evaluate the characteristics of the flow circulation in the B-loop. There are:

(a) buoyancy induced flow and fluid stratification,

(b) cross flow momentum exchange between the HPI jet and the loop flow in the region of the HPI injector, and

(c) shear fluid entrainment and growth of the fluid layers near the boundaries of the HPI jet.

In order to make use of the EPRI data, an analysis was performed to determine the B-loop flow required (assuming the flow to be going towards the downcomer at a hot temperature equal to the temperature measured in the A-loop) to give a mixed coolant temperature equal to the measured temperature in the B-loop. The results of this "flow" analysis are provided in Figure 3.5. For low values of the ratio of the loop flow to the injection flow, the B-loop measurement is in good agreement with the EPRI test data.

The minimum temperature to which the downcomer could have been subjected is essentially the temperature measured in the B-loop. The EPRI data does not appear to support either large flows towards the downcomer from the B-loop or temperatures lower than those measured in the B-loop.

Fracture mechanics analyses were performed assuming the downcomer did cool down as indicated by the measured temperature. Two cases were studied (see Figure 3.6). The worst case, Case 2, bounds the data. This analysis indicated that no crack initiation occurred at Ginna. (A conservative value for the RT_{NDT} of 225° F was used). The total stress intensity factor calculated by combining the effects of thermal stress, pressure stress and that due to the

BEST DOCUMENT AVAILABLE

cladding peaked at less than 75 Ksi-in. The critical value of fracture toughness never got below 100 Ksi-in.)

We have also examined the Ginna scenario to determine if any actions or variations on the scenario could have directed the flow of "cold" HPI water into the vessel. If it is assumed the enhanced flow of cold water away from the vessel was due to the open PORV in the hot leg of the broken generator loop, then the same scenario, but with the pressurizer located in the loop with the intact steam generator, needs to be examined. This is because opening the PORV in the hot leg of the loop with the intact steam generator could put the low pressure point in the system in a location such that HPI water would preferentially flow towards the vessel to reach the PORV rather than away for the vessel.

A similar situation could exist if high point venting at the top of the vessel occurred. However, high point vent operation has not been authorized by the staff.

The above two scenarios describe a general class of events in which one loop is stagnant and cold with respect to the other loop. The general concern is that a venting action could draw relatively cold HPI water into the vessel prior to being mixed by a loop circulation flow.

Based on the above concerns, the staff determined that the licensee should take the following actions:

1. Within six months, review and identify potential transients and accident scenarios that could produce relatively stagnant flow conditions in a coolant loop, and examine the effect of the operator taking actions which would draw the cold water into the vessel. For these scenarios, review and modify procedures and train operators as necessary to prevent or minimize the flow of cold water into the vessel.

2. In the long term, include an evaluation of the scenarios identified above in the overall resolution of the pressurized thermal shock issue. Modify

equipment, procedures and operator training in accordance with the resolution of that issue.

The licensee has committed to supply both evaluations.

3.5.3 Conclusion

The staff conclusion is that a low flow pattern existed in the B-loop, most probably away from the downcomer towards the steam generator (break location). The B-loop temperature indication is consistent with the simplified model developed by the Task Force and is further supported by Creare/EPRCI test data. A conservative fracture mechanics analysis indicates no crack initiation for this event.

3.6 Hydrogen Transfer

3.6.1 Background

Excess hydrogen is added to scavenge free oxygen that could contribute to corrosion problems.

Following the incident on January 25, 1982, samples of the faulted loop steam generator space and the pressurizer vapor space indicated significant hydrogen concentrations.

As a result, the licensee performed a hydrogen transfer analysis. The purpose of this analysis was to show that the amount of hydrogen found in the pressurizer and in the vapor space of the faulted steam generator was from the hydrogen dissolved originally in the primary coolant. The licensee has also indicated that there was no oxygen present in the waste gas removed from the primary system. The licensee concluded that at no time during the steam generator tube rupture incident was hydrogen generated in the core. The concentrations of hydrogen in the pressurizer and the steam generator vapor space were determined when the reactor was in cold shutdown condition. The hydrogen concentration in the faulted steam generator vapor space, originally

reported by the licensee in the submittal (Ref. 3.7) was in error. However, this error was corrected and the final analysis was provided on May 7, 1982.

3.6.2 Evaluation

The licensee's analysis consisted of a hydrogen mass balance performed for the primary coolant system and for the secondary side of the steam generator. Hydrogen transfer from the primary system to the secondary side of the steam generator through the ruptured tube was considered. Also, hydrogen losses in the condenser and the pressurizer relief tank were included. By this mass balance the licensee demonstrated that the hydrogen inventory existing at different locations in the primary and secondary systems after the incident could be accounted for by the hydrogen which was originally dissolved in the primary coolant and then released during the incident. The licensee concluded that the steam generator tube failure incident did not promote any reactions which could result in the production of hydrogen. Hydrogen could be generated either by metal-water reaction of zirconium or by radiolytic decomposition of reactor water. The metal-water reaction requires fairly elevated temperatures which can occur only if the core is at least partially uncovered. Radiolytic decomposition of water would, in addition to hydrogen, generate stoichiometric amounts of oxygen. Since no core uncovery occurred during the incident, and since no oxygen was detected in the gases transferred from the primary systems to the waste gas system, there is no evidence that these reactions occurred.

3.6.3 Conclusion

Based on our independent evaluation, we agree with the results of the licensee's analysis and conclude that there was no generation of hydrogen during the tube rupture incident.

3.7 Fuel Performance

3.7.1 Background

The chronology of events that occurred when the steam generator tube ruptured on January 25, 1982 has been reviewed with respect to possible effects on the

fuel. The data indicated that during the reactor trip, there was a rapid pressure drop of approximately 500 psi in twelve seconds. Later, between 1007 and 1010 psi, another pressure drop of about 500 psi occurred over two minutes. Radiochemistry levels remained essentially constant during the sequence, and the thermocouple readings at the top of the core were always below the saturation temperature.

3.7.2 Evaluation

3.7.2.1 Mechanical Design Considerations

In the licensee's April 12, 1982 "Incident Evaluation" (Ref. 3.1), three fuel performance mechanical design considerations are addressed:

1. Cladding mechanical behavior
2. Cladding metallurgical behavior
3. Fuel assembly liftoff

With respect to the first issue, cladding mechanical behavior, the primary concern was the potential for cladding deformation and rupture, taking into consideration the cladding temperatures (~650°F peak), pressure differential (1200 psi max.), and rate of depressurization (said to be no greater than about 40 psi/sec (Ref 3.6). Based upon burst test information provided in NUREG/CR-1729 (Ref 3.7), the conditions encountered during the Ginna steam generator tube rupture incident were not sufficient to cause cladding deformation or fracture. For example, at cladding temperatures near normal operating temperature (i.e., ~650°F), cladding failure would not occur until pressure differentials of about 10,000 psi were obtained. Therefore, we agree with the licensee and the fuel vendor, Exxon Nuclear Company (ENC), that there is reasonable assurance that the mechanical integrity and dimensions of the cladding were unaffected by the steam generator tube rupture event.

With respect to the metallurgical behavior of the cladding, the lack of any significant temperature rise (thermocouple readings at the top of the core reportedly remained below the saturation temperature) assures that the Zircaloy tubing metallurgy remains unaffected.

With regard to the third mechanical design issue, fuel assembly liftoff, it was postulated in RG&E's April 12, 1982 submittal that the rapid pressure drop that occurred during the reactor trip could have resulted in a pressure differential between the upper and lower parts of the core sufficient to cause the fuel assemblies to move upward. Subsequent calculations, however, indicated that there was no pressure differential vertically across the core (Ref 3.6). Therefore, we conclude that there is reasonable assurance that the fuel assemblies were not subjected to lift-off during the transient.

3.7.2.2 Core Transient Consideration

The rapid depressurization during the first few minutes of the Ginna steam generator tube rupture incident could have caused reduction in Departure from Nucleate Boiling Ratio (DNBR) and resulted in fuel damage. In order to determine whether any fuel rod experienced DNB during this depressurization transient, the licensee has performed a DNBR calculation. During the rapid depressurization, the reactor remained at approximately 70% of the rated thermal power and the reactor coolant pressure dropped from about 1900 psig to 1250 psig. The DNBR was calculated using 70% thermal power and 1200 psia coolant pressure, which is a reasonable assumption because use of a lower pressure would result in a lower Heat Flux (CHF) as well as a lower DNBR. Using the approved W-3 correlation, the licensee critical calculated a minimum DNBR of 2.63, well above the specified acceptable fuel design limit of 1.30 for W-3 DNBR limit.

3.7.3 Conclusion

In summary, the staff concurs with the licensee that the Ginna reactor fuel system was not significantly affected by the steam generator tube rupture incident with respect to cladding mechanical and metallurgical behavior and fuel assembly mechanical response. Also, it is concluded that no fuel damage due to DNB occurred as a result of the transient.

3.8 Plant Water Inventory

3.8.1 Background

The licensee's analysis of the plant water inventory during the January 25, 1982 event was reviewed to determine if this information identified the need for modifications in the plant or its procedures prior to restart. The licensee's analysis was compared to the NRC staff analysis presented in NUREG-0909 (Ref 3.3). The licensee's comments, dated May 5, 1982 (Ref 3.8), on the significant findings of NUREG-0909 were also reviewed.

3.8.2 Evaluation

Although there are several areas of minor difference between the licensee's analysis and staff's analysis there is only one major disagreement relative to the plant inventories. The minor differences include: the licensee's failure to account for the water injected into the RCS from the Reactor Makeup Water Tank (integrated flow from this tank is printed on Log Sheet Section 3 from the hourly computer log); the licensee's use of design setpoint levels rather than recorded levels from the Daily Surveillance Log for the Boric Acid Tank levels; and the licensee's use of 84% level for the final RWST level rather than 83% as indicated in the Daily Surveillance Log (the 1% difference corresponds to 3425 gallons). The major difference relates to the estimate of the auxiliary feedwater flow and the steaming rate during the 18 minutes following the reactor trip. The licensee's report states that the auxiliary feedwater flow was terminated to the B steam generator after three minutes (9:29 a.m. to 9:32 a.m.). Their basis for this position is that the computer alarm printer indicates that the steam supply to the turbine-driven auxiliary feedwater pump was from the B steam line which was terminated at 9:32 a.m. and that the plant operators have stated that feedwater flow to the B steam generator was terminated at that time. However, the NRC staff report, NUREG-0909, indicates that the feedwater flow to the B steam generator continued until 9:45 a.m. when the steam supply to the turbine-driven auxiliary feedwater pump from the A steam line was terminated. The staff's determination is based on the fact that, (1) feedwater from the turbine-driven pump normally goes to both steam generators,

(2) the turbine-driven pump continued to run until 9:45 a.m. (as seen in the level increase in the A steam generator), and (3) the pressure changes in the B steam generator after the MSIV closed at 9:40 a.m. cannot be explained without assuming the continued flow of cold auxiliary feedwater. We believe that the measured and recorded plant data generally provide a more reliable indication of plant response than does the recollections of the plant operators. Therefore it is likely but not certain that the licensee's evaluation is incorrect on this point.

In terms of the steam flow to the condenser during the first few minutes following the reactor trip, the licensee has estimated the steam flow to have been 41,000 lb while the NRC staff's estimate from NUREG-0909 is 21,000 lb. The licensee's estimate comes from an estimate of the flow through the dump valve (the valve positions are recorded but only to the nearest minute) while the NRC staff's estimate is based on an energy balance (that is 50% of the steam generation required to remove decay heat and cooldown the RCS at 100°F/hr). Both methods are subject to uncertainty since neither the valve opening and closing times nor the RCS temperatures and decay heat are known accurately. With the limited information available we cannot conclusively state which analysis more accurately reflects the actual plant conditions. However, two general conclusions can be drawn. First, both analyses of the excess of water which would not be stored in the B steam generator (and was therefore presumably discharged through the safety valve), that is, the 117,000 lbs estimated by the NRC staff and the 73,000 lbs estimated by RG&E, greatly exceed the licensee's estimate of the 27,000 lbs discharged through the safety valve. Second, the only area in which these plant inventory analyses suggest that there is a need for action before plant restart is the need to inspect the B steam generator safety valve which may have leaked excessively on some occasion during the tube rupture event. The licensee has inspected all of the steam generator safety valves and the results of these inspections and repairs is discussed in Section 5.4.3.3 of the licensee's report (Ref. 3.2). The staff's evaluation of these actions is discussed in Section 6.3 of this Safety Evaluation Report.

3.9 B Steam Generator Level Indication

3.9.1 Background

The variations in the B steam generator level during the first five minutes are shown in Figures B-3 and B-4 of Reference 3.2. These figures include information from both the wide-range and narrow-range level instruments. Figure 3.7 shows the locations of the wide-range and narrow-range instrument taps.

3.9.2 Evaluation

These level instruments are, in fact, measurements of the differential pressure between the pressure taps. The narrow-range instrument is calibrated so that a 100% indicated value corresponds to the differential pressure of a column of water with a height equal to the elevation difference between the pressure taps, at a temperature at the normal operating temperature of the steam generator. The wide-range instrument is calibrated so that a 100% indication corresponds to the differential pressure of a column of water with a height equal to the elevation difference of the wide-range pressure taps, at a temperature of approximately 100°F. During the first five minutes of the event, the wide-range and narrow-range level instruments appear to have operated as designed, that is, they accurately reflected the changes in the differential pressure in the steam generator downcomer region. The rapid drop in the narrow-range level, immediately following the reactor trip, was caused by a redistribution of water from the downcomer region into the tube bundle region. This redistribution normally occurs after a reactor trips and is the result of the rapid decrease in the rate of steam generation in the tube bundle and the associated decrease in the pressure drop caused by the motion of the steam and water through the tube bundle, the dryers and the moisture separators.

The wide-range instrument is much less sensitive to the flow redistribution since it monitors differential pressure down to an elevation just above the tube sheet while the narrow-range level instrument only monitors differential pressure near the top of the downcomer. In addition, the injection of cold auxiliary feedwater into the steam generator downcomer results in an increase

in the density of the fluid in this region and a corresponding increase in the differential pressure. This increase can be seen on the wide-range instrument since the effect is larger than the flow redistribution effect. On the narrow-range instrument the density increase is overwhelmed by the flow redistribution effect and a net drop in level is seen.

3.9.3 Conclusion

In summary, both instruments accurately monitored the change in differential pressure in the steam generator downcomer, the narrow-range instrument being a better indicator of the water level in the downcomer and the wide range instrument being a better indication of changes in the total water inventory of the steam generator.

3.10 References

3.1 Rochester Gas and Electric Corporation, Robert Emmett Ginna Nuclear Power Plant No. 1, Final Facility Description and Safety Analysis Report, Vols 1-3, Docket 50-244, March, 1969.

3.2 Incident Evaluation, Ginna Steam Generator Tube Failure Incident, January 25, 1982, R.E. Ginna Nuclear Power Plant. Docket 50-244, April 12, 1982.

3.3 NUREG-0909, NRC Report on the January 25, 1982 Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant, April 1982.

3.4 Incident Evaluation, Steam Generator Tube Rupture Incident, R.E. Ginna Nuclear Power Plant, Docket 50-244 (Supplement on Thermal Transient on Reactor Coolant System), April 26, 1982.

3.5 EPRI NP-3212, Fluid and Thermal mixing on a Model Cold leg and Downcomer with Loop Flow, Interim Report, January 1982.

3.6 M. Tokar and D. Powers (NRC), Telecommunication with J. Cook (RG&E) and G. Buffleman (ENC), May 3, 1982.

3.7 Evaluating strength and Ductility of Irradiated Zircaloy--Task 5, NUREG/CR-1729 (BMI-2066), Vol. 1, May 1981.

3.8 Response to NUREG-0909, Steam Generator Tube Rupture Incident, R. E. Ginna Nuclear Power Plant, Docket No. 50-244, May 5, 1982.

8521 DOCUMENT HANDLING

BEST DOCUMENT AVAILABLE

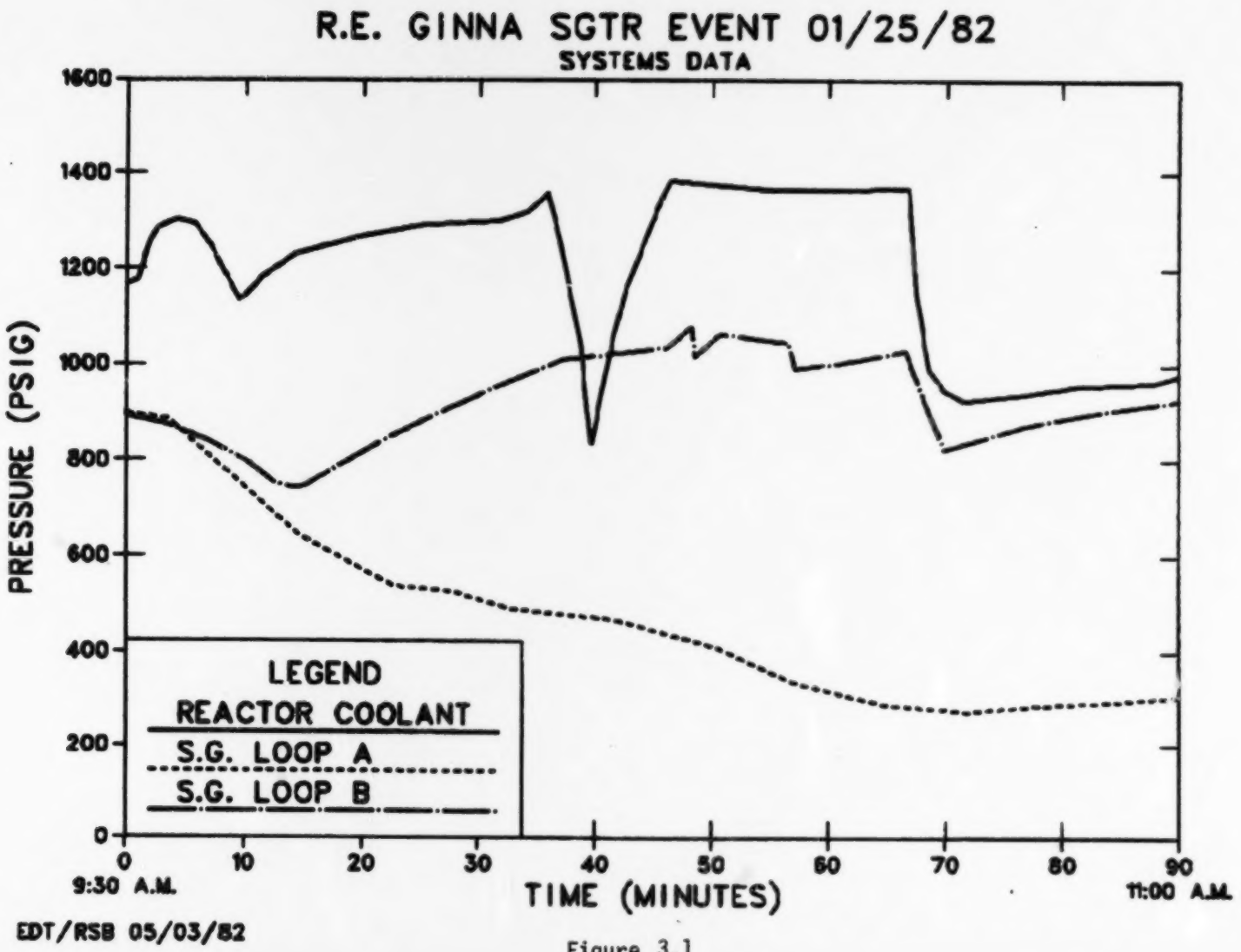


Figure 3.1

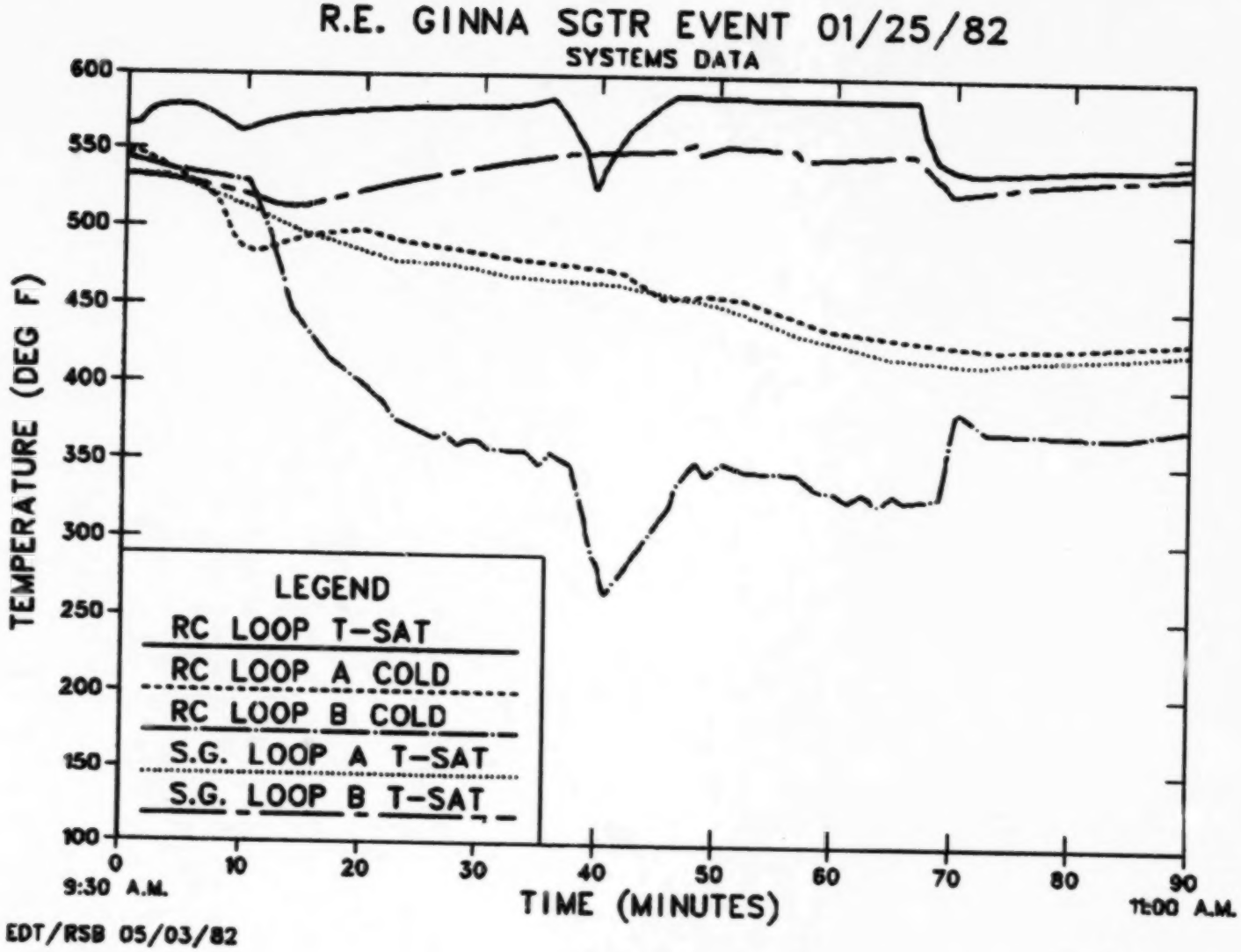


Figure 3.2

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

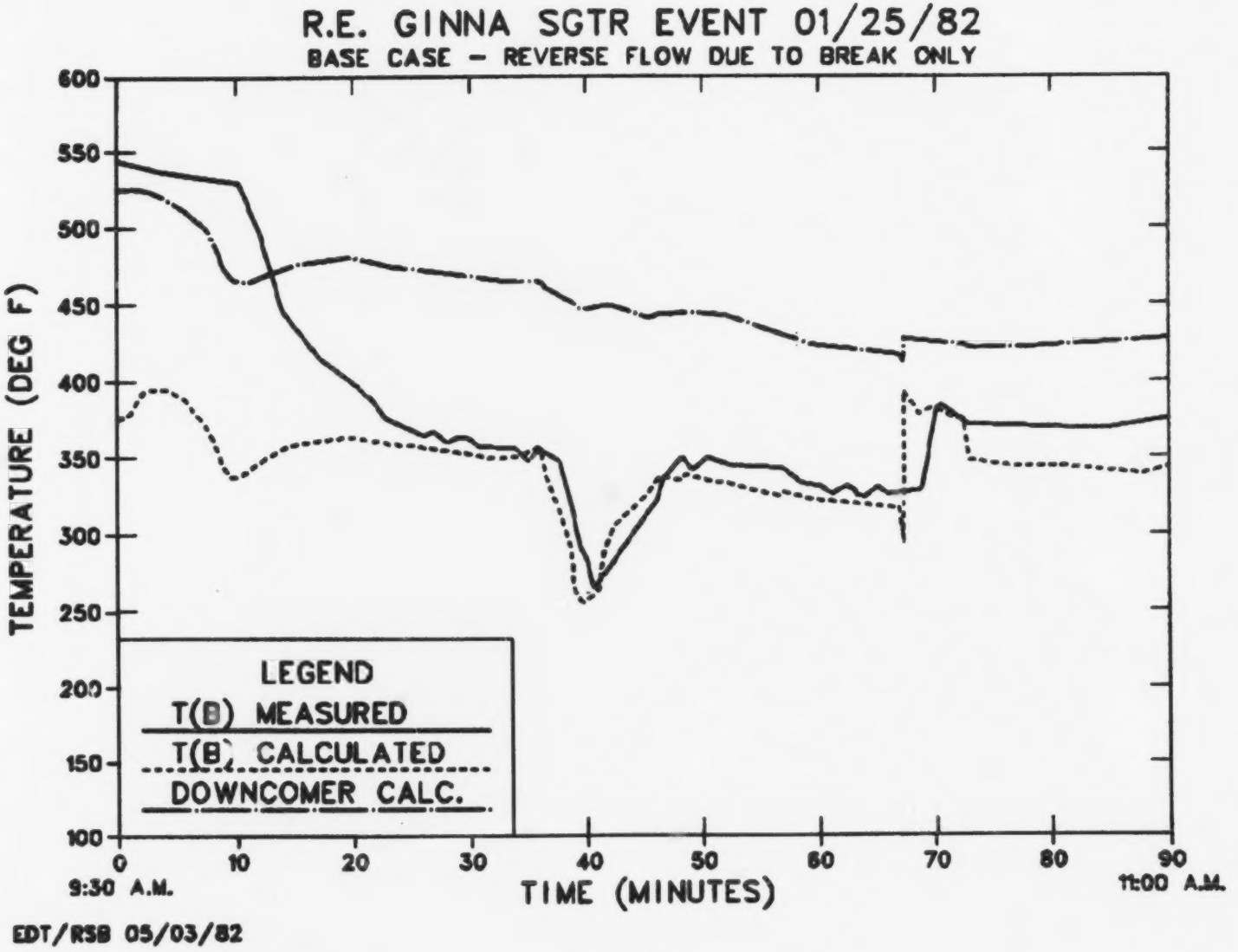


Figure 3.3

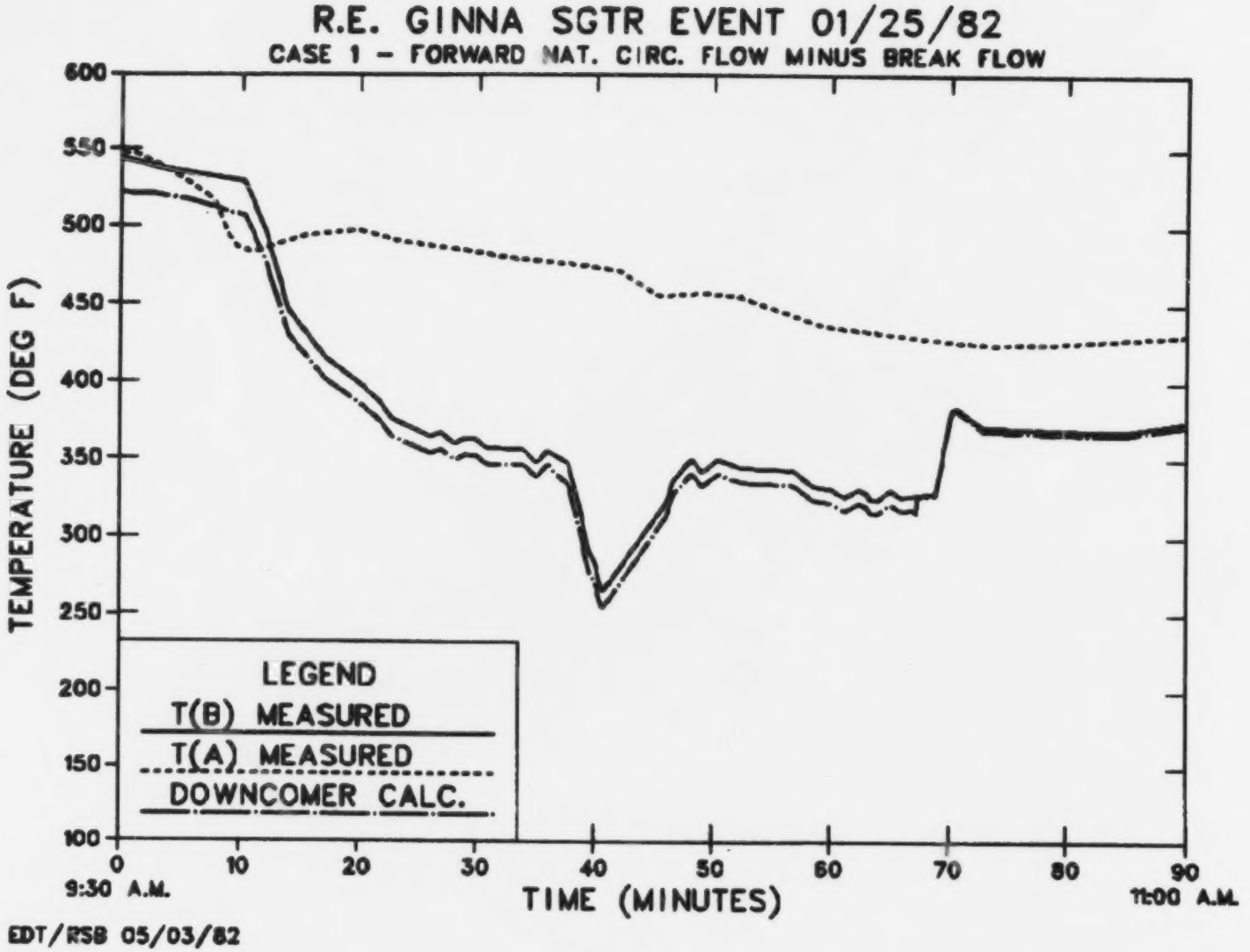


Figure 3.4

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

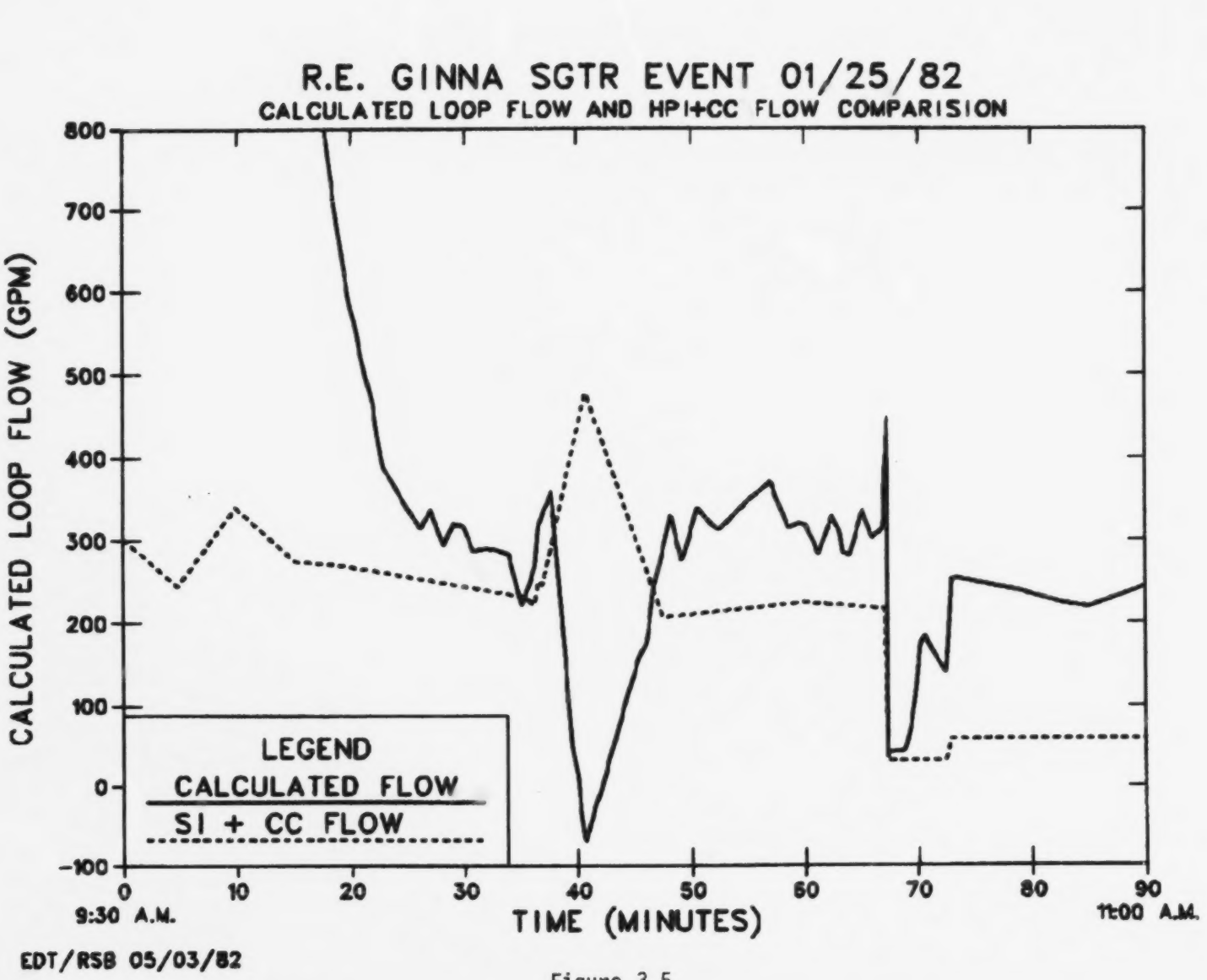


Figure 3.5

Ginna Restart SER

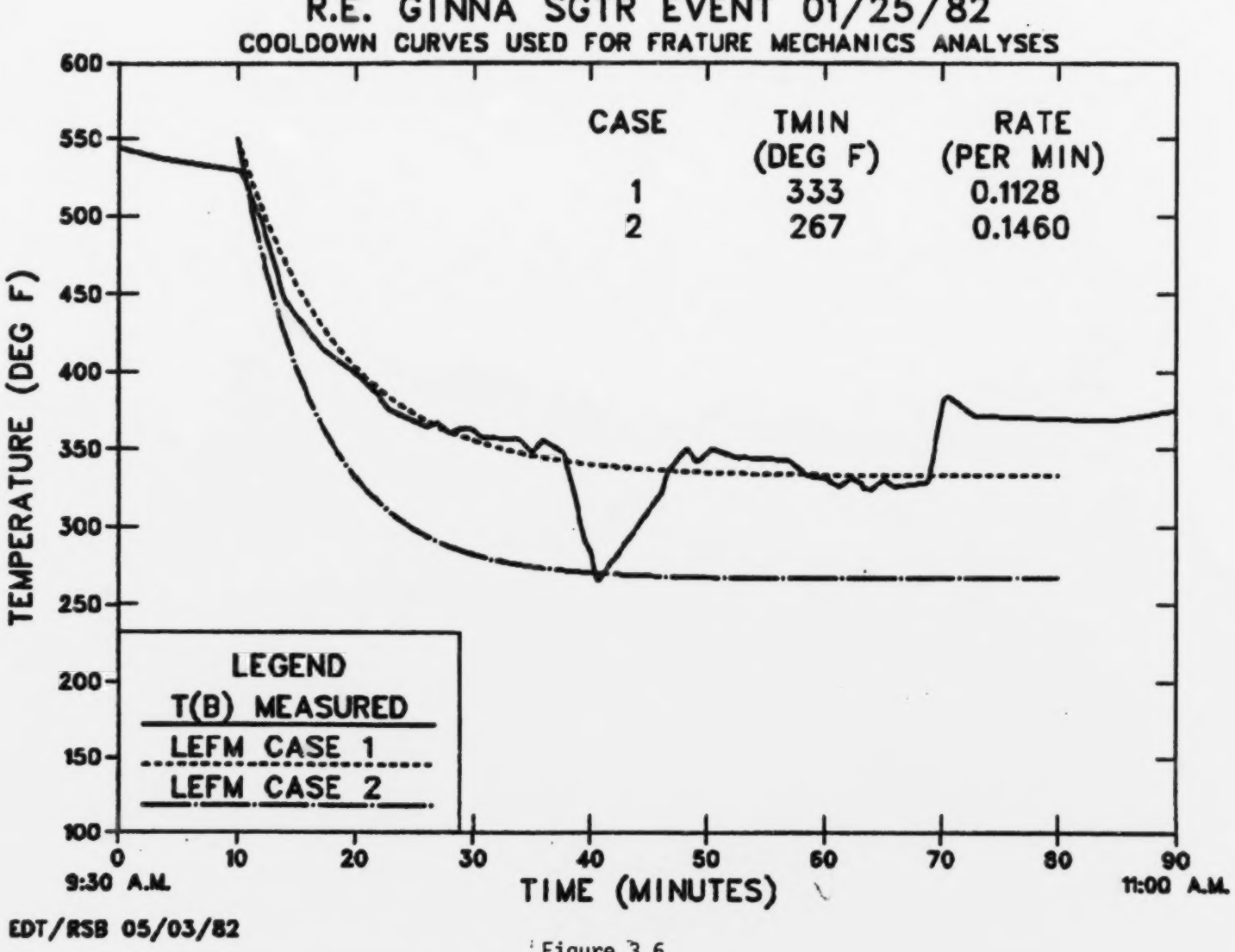


Figure 3.6

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

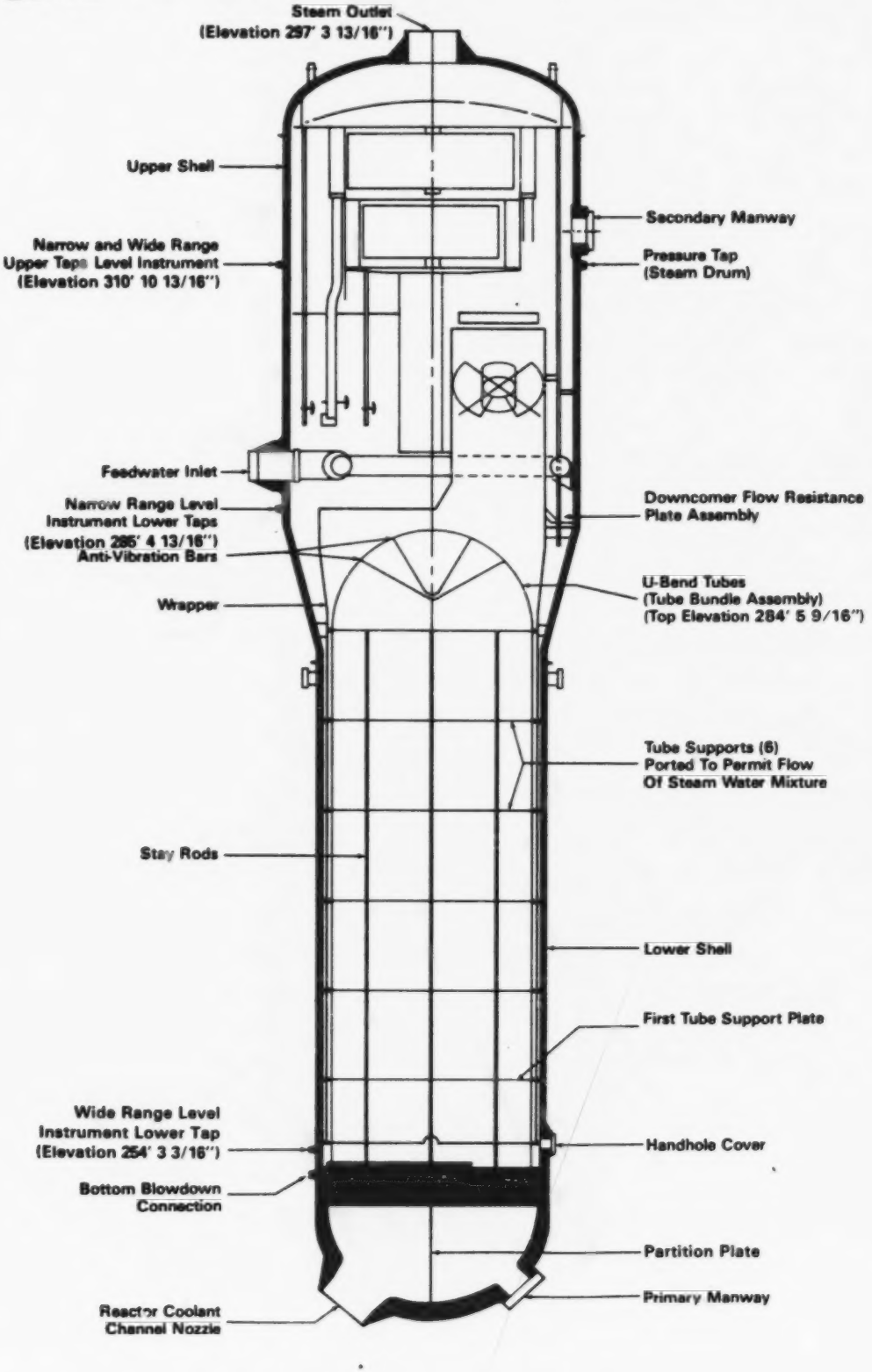


Figure 3.7 Ginna Steam Generator showing
locations of instrument taps

4.0 OPERATOR RESPONSE

4.1 Procedures

Following the steam generator tube rupture (SGTR) event, multiple control room alarms alerted the operator to a reactor coolant system (RCS) rapid depressurization. The air ejector radiation monitor alarm indicated the existance of a steam generator tube rupture and the continuing reactor coolant system pressure drop resulted in an automatic reactor trip and automatic actuation of all three safety injection pumps. The safety injection actuation further caused an automatic containment isolation and tripped the charging pumps.

Various emergency operating procedures were used by plant personnel following the automatic safety injection initiation to diagnose and track the course of the event and to complete the immediate actions required. The procedure for SGTR contains a table listing the various plant parameters which may be exceeded during the event, to enable the operator to verify instrument readings at various control consoles in the control room.

The licensee has identified the following procedures that were used for mitigation for the event:

- E-1.1, "Immediate Actions and Diagnostics of Spurious SI, LOCA, Loss of Secondary Coolant and Steam Generator Tube Rupture,"
- E-1.4, "Steam Generator Tube Rupture."
- E-1.5, "Void Formation in the RCS."
- O-2.1, "Normal Shutdown to Hot Shutdown."
- O-2.2, "Plant Shutdown from Hot to Cold Shutdown."

BEST DOCUMENT AVAILABLE

- O-100, "Draining the RCS Following a S/G Tube Rupture."

4.2 Evaluation

Our review of the initial plant response has indicated that procedural guidelines were followed by plant personnel, and the automatic actions predicted to occur in Procedures E-1.1 were confirmed. Other immediate operator actions required by this procedure commenced following actuation of safety injection. The initial alarms that alerted the operators to the rapid depressurization of the RCS occurred at 9:25 a.m., and at 9:28 a.m. the continuing depressurization resulted in the automatic reactor trip and automatic actuation of the safety injection system.

4.2.1 Reactor Coolant Pump Operation

4.2.1.1 Reactor Coolant Pump Trip

The licensee has stated: "Reactor coolant pump trip was performed at 9:29 a.m., less than 1 minute after Safety Injection (SI) pump operation was verified and RCS pressure was less than 1715 psig, in accordance with E-1.4. Pumps were tripped based on a trip pressure of 1715 psig as opposed to 1350 psig as suggested in the Westinghouse Owners Group Procedure Guidelines, because of lack of instrumentation which is qualified below 1717 psig. However, use of the lower value would not have resulted in any change to the transient, since RCS pressure dropped below 1350 psig within a minute of dropping below 1715 psig."

Continued operation of the reactor coolant pumps during a SGTR event is desirable for several reasons. First, continued forced circulation of primary coolant allows better and more uniform control of the primary system cooldown. Second, pump operation keeps pressurizer spray available for pressure control. Third, forced circulation helps prevent the formation of sizable bubbles in the reactor coolant systems. Considered against this, however, is the problem that for certain small break loss-of-coolant accidents (LOCAs), continued pump operation will result in a larger mass flow rate out of the breaks, and the possible formation of a significant void fraction in the coolant system. This

is a problem because SGTR and small break LOCA events exhibit many similar symptoms and operators may experience difficulty in quickly determining the precise event.

In a subsequent submittal on May 4, 1982 (Reference 4.2) the licensee stated that he was installing qualified pressure instrumentation during the current outage and intended to adopt a lower pressure pump trip criterion as recommended by the owners group. However as stated above this would have little effect on tripping pumps during events such as the Ginna SGTR which was a large single tube rupture. The licensee initially recommended consideration of long term action to attempt to eliminate the RCP trip criteria for steam generator tube rupture events or provide additional options to maintain RCPs in operation during such events.

The licensee has committed to perform a formal study of possible solutions to the RCP trip issue, with the purpose of finding a method for keeping the RCPs operational during SGTR events such as occurred at Ginna. This study will consider such solutions as additional HPI capacity, more discriminating criteria for RCP trip, or, if RCP trip cannot be avoided, a qualified auxiliary spray capability. This study is expected to be completed within a 6-month period with the results formally submitted to NRC at the end of this period.

In the interim, a lower value of the RCP trip pressure will allow the RCPs to remain in operation for a range of smaller steam generator tube ruptures and will thus prevent significant bubble formation in the reactor coolant system.

4.2.1.2 Reactor Coolant Pump Restart

With respect to pump restart the licensee said: "The "A" RCP was restarted at 1122, after the E-1.4 emergency procedure criteria were met. The decision was made to start the RCP, even though the pressurizer was suspected to be water solid, by pressurizer level indication of 100%. The reactor coolant pump was restarted very deliberately, after checking all relevant parameters necessary for RCP operation, such as seal injection flow, lube oil pump operation, #1

seal differential pressure, component cooling water flow, and the NPSH curve for the reactor coolant pump."

The licensee first proposed to add a note after step 3.18 to read as follows: "Note: The RCP may be started with a full pressurizer, if the core exit thermocouple temperature is greater than 330°F."

The licensee further stated that, "This note serves to eliminate hesitancy to start an RCP with a water-solid pressurizer. Although this change has been made in the procedure, the RCP restart conditions are currently under review by Westinghouse."

In its May 4, 1982 submittal, the licensee changed the proposed note to require a bubble in the pressurizer prior to pump restart. We understand that drawing a bubble in the pressurizer should not significantly delay restart but this item will be confirmed by the licensee as part of his study of this issue. We also believe that the frequent recent procedural changes on this issue further emphasize the need for positive resolution of the pump trip and restart issues. For the pump restart procedure as well, the licensee recommended that additional guidance be provided relative to operator actions with a water solid pressurizer.

The licensee further committed to formally study the question of RCP restart criteria in conjunction with the RCP trip study within 6 months. The objective of this effort is to establish criteria for RCP restart that will not jeopardize plant safety or result in operator confusion. The study will address such issues as:

- The need for a bubble in the pressurizer prior to restart.
- The minimum volume of water needed in the pressurizer prior to restart, considering the maximum volume of steam that could potentially exist in the vessel head.
- The need for a system subcooling margin prior to restart, and the effects of bulk system flashing if the pressure drop due to reactor

vessel head bubble collapse following RCP restart drops the system pressure below saturation.

The licensee also proposed to provide additional guidance relative to operator actions in the event of a water solid pressurizer, especially for pump restart. The staff agrees with this action. Additionally, for the long term the licensee will also examine the procedures in the light of obtaining and requiring the earliest possible restart of a pump, if pumps are to continue to be tripped under existing criteria. Early coolant pump restart makes pressurizer spray available and restores the use of normal pressure control, thus providing much better control over the ensuing depressurization. Further, forced circulation provides more uniform reactor coolant system cooling and helps prevent formation of sizeable bubbles in the reactor coolant system that could impede decay heat removal.

The technical specifications on coolant activity (see sec. 8.1) will be reduced until the licensee has achieved final resolution on RCP operation. We expect that continued RCP operation during an SGTR event will allow a more controlled depressurization, reduce steam generator overfilling, and prevent prolonged release of activity to the environment. The reduction in technical specifications coolant activity assures that prolonged releases such as occurred at Ginna will not violate 10 CFR 100 limits.

4.2.2 Verification of Natural Circulation

Following the plant depressurization due to the stuck open PORV and the development of the steam bubble in the reactor vessel head, plant procedure E-1.5 "Void Formation in the RCS," was utilized by the operators. The procedure called for determining core exit thermocouple temperature readings, which was done regularly to confirm an adequate margin to saturation. Although adequate core cooling existed, the operators continued to supply high pressure SI water and started a reactor coolant pump to collapse the steam bubble that had formed above the core under the reactor vessel head. The licensee has revised procedure E-1.4 and has included instructions for the operator to actuate the control rod drive mechanism and reactor compartment cooling fans, in order

to help cool the reactor vessel head region and minimize vessel head-to-reactor loop temperature difference, thus reducing the potential for bubble formation.

The licensee is further planning to provide additional guidance for operator action in the event of an actual or suspected void formation in the reactor vessel upper head region during an SGTR. The staff will review this additional guidance when transmitted as long-term procedural change. In the short term, however, procedure E-1.4 has been changed to note that a bubble can form in a hot vessel region during an STGR. The procedure used to perform a natural circulation cooldown, 0-2.4, "Plant Shutdown from Hot Shutdown to Cold Shutdown during Blackout," provides additional information on how to recognize and cope with these bubbles.

4.2.3 Safety Injection and Containment Isolation Reset

Following safety injection actuation, the containment isolated automatically resulting in the isolation of reactor coolant letdown and interruption of instrument air to the pressurizer PORVs. The plant emergency procedures require the verification of isolation prior to positive identification of the event, as a precaution to limit the leakage of radioactive fluids through containment should the event cause serious damage to the core. Following the positive identification of the event, operators are instructed to reset the safety injection and containment isolation signals in order to regain manual control of equipment and systems. Isolation of instrument air to the PORV did not result in loss of PORV control, since the diverse nitrogen supply was available to the PORV in place of the instrument air.

Reset of safety injection would permit reset of containment isolation, which would further permit the operators to reestablish instrument air to the containment for operation of air-operated valves. These valves include reactor coolant system letdown, normal pressurizer spray, auxiliary pressurizer spray, reactor coolant pump No. 1 seal return, pressurizer PORV, normal charging, and auxiliary charging. Reset of containment isolation would permit the establishment of normal seal water supply and return for the reactor coolant pumps. The limitations imposed by the transfer logic circuitry and the procedures cause

delay in the utilization of equipment which can mitigate the consequences of a steam generator tube rupture.

In order to ensure that the Safety injection (SI) pumps are supplied with water from the refueling water storage tank (RWST) when SI is reset, the licensee has revised the procedures to require that the supply of water has been transferred to the refueling water storage tank (RWST) from the boric acid storage tank (BAST) before reset of SI. The staff has determined that the licensee should perform a long term review of the need for transfer of water supply before resetting SI. The safety injection pump suction shifts automatically from the boric acid storage tank to the refueling water storage tank on low level in the BAST, only if the safety injection signal is not reset. The licensee's steam generator tube rupture procedural requirements prohibit the operators from resetting safety injection signals until the automatic transfer has taken place. However, a manual or automatic transfer logic independent of safety injection reset would have allowed the operator to reset safety injection approximately 2 minutes into the event.

The licensee has committed to study this issue and report his conclusions within six months.

4.2.4 Restart of Charging Pumps

Following the identification and isolation of the faulted steam generator, procedure E-1.4 requires depressurization of the primary system to equalize the primary and secondary pressure in order to limit leakage of the primary coolant through the faulted steam generator. Therefore, prior to depressurization of the primary system, plant personnel are instructed by procedures to start all available charging pumps. The plant personnel apparently deviated from procedures by restarting only one charging pump. Though the above deviation did not lead to any significant departure from the desired plant cooldown, the staff concludes that additional charging flow would have assured better control during inventory loss from the ruptured tube and the PORV.

4.2.5 Isolation of B Steam Generator (SG) Atmospheric Relief Valve (ARV)

Procedures require that the SG ARV controller be placed in the manual closed position. However, plant personnel misinterpreted this instruction and instead closed the block valve. Therefore, when the steam generator pressure exceeded the safety valve setting the safety valve opened. If the instructions had been followed properly the SG ARV would have opened before the safety valve was challenged, because the SG ARV has a lower setting.

The licensee has included a clarification statement to remove this confusion. The staff agrees that clarification is needed and that the proposed change should remedy this concern.

4.2.6 Operation of Pressurizer Power Operated Relief Valve

The licensee's steam generator tube rupture procedure will usually result in the formation of steam in the reactor vessel upper head area for large break flows. With the reactor coolant pumps tripped, the cooling rate in the reactor vessel head area is slowed because of low flow conditions. Subsequent reactor coolant system depressurization using the pressurizer PORV to limit the break flow would then usually result in steam formation in the reactor vessel upper head. Procedure E-1.4 did not provide information to assist the operator in identifying the formation of a reactor vessel upper head steam bubble or instruct him in the techniques to monitor and safely handle the steam bubble. Neither did the procedure direct the operator to procedures designed to handle the situation.

Procedure E-1.5 "Void Formation in the Reactor Coolant System" did exist and was used; but the procedure did not strictly apply, since it did not address void formation which occurs at core exit temperatures of less than 700°F. The licensee has revised E-1.4 to include guidance on possible bubble formation in the RCS during depressurization. The licensee has also examined E-1.5 to determine whether guidance should be added to anticipate the possibility of bubble formation during depressurization for events such as gross pump seal leakage or for SGTR's. He has concluded that because this procedure would

only be entered in the case of inadequate core cooling, and because the formation of a bubbles in the head would be identified and addressed in other procedures that would be used first, no changes to E-1.5 are necessary. The staff agrees with this conclusion.

The pressurizer PORV and block valve switches are located side by side and appear to be identical. However, the PORV switch is a three-position latching type switch. Although the functions of the switches are clearly noted, there was no obvious way to identify the difference in switch operation or whether the spring-loaded switch had to be held until the motor-operated valve closed or opened fully. The licensee has provided additional labeling for these two switches to clarify their method of operation. The staff finds this corrective action to be acceptable.

The approximate 6-ft separation (Fig. 4.1) between the reactor coolant system wide-range pressure recorder and the pressurizer PORV controls originally required the control room operator to rely on someone else to describe the results of opening the PORV. This resulted in a two-person, multiple, bump-and-wait type of operation. The licensee examined the switch and pressure readout locations and determined that it was necessary to improve the capability of a single operator to operate the PORV control switch and simultaneously observe the results of this action. The licensee has installed a new pressure readout that is directly in front of the operator as he manipulates the PORV (Fig. 4.2).

The pressure transient caused by opening the PORV can be on the order of 400 psi per minute. If depressurization to a specific value is desired as is presently required by the procedures, significant under- or over-shoot can occur. The licensee has revised his procedures to provide additional guidance on this aspect of PORV operation, and the staff has recommended that the licensee consider additional hardware modifications in the future to provide better pressure control.

4.2.7 Safety Injection Termination

Safety injection was manually terminated by plant personnel after the termination criteria included in the procedure were met and after the operators were confident that core cooling would be maintained following its termination. A delay in the termination was attributed to the operator concern that a steam bubble existed in the vessel head and the judgment that in addition to the termination criteria other confirmatory information was required to assure that natural circulation and subcooling would be maintained at the core exit. The Westinghouse Owners Group analysis which supports the emergency response guidelines predicts the formation of voids in the vessel head region. The licensee has revised his procedures to require termination of safety injection when certain criteria are met, regardless of the existence of a bubble in the head.

Furthermore, the procedures did not specifically instruct the operators to consult the saturation curve, included in the procedures, or the subcooling meter prior to termination of safety injection. However, this requirement was met as a result of the operators' familiarity with the bases and assumptions underlying the procedures. The licensee has subsequently revised his procedures so that operators are specifically instructed to confirm that subcooling is maintained subsequent to interruption of the safety injection pumps.

The staff agrees with the licensee that the operators' concern for adequate core cooling was the paramount reason for continuing to operate SI pumps after the termination criteria had been reached. The operators were faced with a choice between reliable knowledge of core cooling status with the high pressure SI pumps running, and continued opening of the faulted steam generator safety valves with accompanying release of radioactivity and the possible uncertainty in reactor coolant inventory. These competing safety concerns were appropriately considered and when the operators concluded that sufficient inventory existed and the core would be adequately cooled, they terminated SI.

The staff concludes that the licensee has satisfactorily considered the circumstances surrounding termination of SI with a bubble in the RCS. The proposed

changes to procedures to clarify SI termination with voids in the upper head region and the addition of a subcooling requirement for termination adequately resolves the staff's concerns in these areas. It is noted, however, that the pressurized thermal shock aspects of continued SI were not adequately considered by the plant personnel prior to SI termination. This is discussed further in Section 3.5.

4.2.8 Isolation of Condenser

During the course of the event plant personnel took the condenser out of service by tripping the condensate pumps. This action was taken to prevent contamination of the full flow condensate demineralizer system and of the condensate storage tanks. The demineralizers would have become contaminated by the condensate from the damaged steam generator. The condensate storage tank (CST) would also have become contaminated due to flow from the condensate pump discharge to the CST. Tripping the condensate pumps takes the condenser out of service because continued accumulation of condensed steam would flood the hotwell and because condensate flow is needed to cool the air ejectors. The air ejectors are necessary to maintain vacuum in the condenser.

Since the tripping of the condensate pumps removed the main condenser as the heat sink for decay heat and reactor coolant system cooldown, the A steam generator and thus the reactor coolant system, was cooled by relieving secondary system steam to the atmosphere through the A SG ARV.

It should be noted that the licensee's decision not to utilize the condenser but to dump steam to atmosphere using the A SG ARV left fewer means available for primary energy removal should a problem with the ARV have occurred. For example, if the control system for the ARV or the valve itself had failed such that the valve would not open, and since the A SG MSIV was closed and vacuum broken on the condenser, there would be no means readily available to continue the steam release mode of energy removal. The primary pressure and temperature would have increased until one of the following occurred:

a. Repair of the ARV, or its controls, or

b. Manual-local operation of the ARV, if possible, or

c. Lifting of the SG safety valves, or

d. Open the A SG MSIV and regain the use of the condenser.

The licensee has stated that if the condenser and its support systems are hot, the condenser can be available within about 15 to 20 minutes. Therefore, should the first three items above not be possible, energy removal capability and continuation of the cooldown could probably have been regained within about 15 to 20 minutes. The resulting leakage into the damaged SG and the offsite releases resulting from its safety valve lifts cannot be estimated since it would depend on the system parameters and operator actions at the time of the occurrence.

Since the condensate storage tanks would become contaminated in a SGTR without isolation of hotwell "reject" flow, the licensee proposed to add the following action step 3.19.1 and a procedural caution as shown below:

"Isolate reject to contain the possible contaminated hotwell, until activity sample allows water usage.

CAUTION: Do not overfill the condenser."

The licensee states, "This step lessens the contamination of the condensate system in the turbine building, thus lessening the contamination of the feedwater for the good SG, as well as the turbine building in general."

Since the decision to secure the condenser reduced the means readily available for energy removal and system cooldown in the event of a failure of the ARV, and resulted in releases from the A SG to atmosphere, in addition to the proposed procedure change, the licensee has committed to perform a long term evaluation to determine the criteria which should be provided in the procedures for deciding

when to discontinue the use of the main condenser in favor of the atmospheric steam dump. These criteria would assume that offsite power is available and would be based on minimizing release of radioactivity offsite.

4.2.9 Pressure Control

Pressure control of the reactor coolant system during the event was maintained by manual control of the safety inspection pumps, by charging flow, by the pressurizer PORV, and by operation of the reactor coolant pumps, as discussed in the other individual sections of this SER.

Our review of the procedures has revealed that operator errors that may result in damaging overpressurization in the vessel, following steam generator tube rupture, are highly unlikely because such a condition can only be developed from a prolonged operation of the safety injection system in violation of the termination criteria. Generally there is sufficient time to evaluate and terminate an unacceptable overpressure condition before the pressure reaches damaging levels. Conversely, it is highly unlikely that core damage can occur from excessive depressurization of the primary system, as a result of operator errors. Operators have a variety of means to regain core cooling in the event of void formation resulting from inadvertent depressurization. The pressure control system, safety injection actuation, and reactor coolant pump operation are available to the operator for effective heat removal and to collapse voids which may form the primary. The staff therefore concludes that no additional automatic pressure control system is needed at Ginna.

4.2.10 Isolation of B Steam Generator

Following the safety injection initiation and an evaluation of plant alarms of air ejector radiation, and steam/feedwater mismatch as indicated by procedures E-1.1 and E-1.4, the operators shut the MSIV of the affected steam generator 15 minutes after the start of the event. Steam generator blowdown radiation alarms and steam generator level alarms did not sound prior to isolation. The operators were able to identify the event before reactor trip had occurred.

Previous analyses in the FDSA (Reference 4.3, see Section 8.1) were performed by the licensee for a steam generator tube rupture of comparable size (843 gpm). These analyses assume isolation of the affected steam generator in either one or 4 1/2 hours following the event, depending on the assumptions made. These analyses were used to determine offsite consequences due to release from the condenser and show that doses to individuals at the site boundary are within guideline values. The FDSA also presents an analysis of the offsite consequence should the entire reactor coolant system volume be released to the environment assuming one percent failed fuel.

The staff reevaluated the consequences of a STGR at Ginna in a Systematic Evaluation Program review described in section 8.1. We noted that continued leakage into the SG after the MSIV had been shut was a result of continued SI operation, and had not been explicitly evaluated in the FSDA. Because the effects of SG overfill were not previously considered, the licensee has committed to a reevaluation of the SGTR event considering the possibility of SG overfill, the resulting effects on SG integrity, and the offsite consequences due to water relief out of the safety valve.

4.2.11 Cooling of the Faulted Steam Generator

Plant cooldown was accomplished according to written procedures with the exception of cooling of the faulted B steam generator. Procedure E-1.4 does not address the technique to be used for cooldown of the faulted steam generator. Oral instructions developed by the Ginna Technical Support Center staff directed operators to fill the steam generator up to a level of about 60% of narrow range, and the pressurizer to an indicated pressure of about 25 psi below the secondary side pressure. The secondary water was allowed to flow through the tube break back into the primary side and the steam generator narrow-range level was allowed to drop to a minimum of about 25% of scale. Boron sampling at half-hour intervals assured no reduction in the required shutdown margin. The feeding of the steam generator and bleeding to the primary was repeated six to eight times in order to accomplish the desired cooling.

The licensee has committed to perform a long-term evaluation of alternative methods for cooling the affected steam generator. The licensee's proposals will be reviewed when the evaluation is submitted for staff review. The procedures are expected to be based on the most recent recommended guidance from the Westinghouse Owner's group on this topic and will consider the various phenomena, such as stratification in the faulted steam generator, which occurred during the event.

4.2.12 Lack of Procedural Coverage for SG with Tube Rupture and Failed SG Safety or Relief Valve

The license's SGTR emergency operating procedure does not contain instructions for coping with a failed open or leaking ARV or Code safety valve on the steam generator with a ruptured tube. During the Ginna SGTR event with the SG ARV blocked, the lowest setpoint Code safety valve was challenged several times. Following each repeated opening, the valve shut at successively lower setpoints. Failure of a safety valve to shut would result in depressurization of the secondary side of the steam generator followed by depressurization of the primary through the ruptured tube. This condition would complicate core cooling and increase the amount of activity released to the environs.

The licensee has agreed to perform a review of this issue within 6 months and to provide emergency procedure instructions for this contingency including SG filling. The latest version of the Westinghouse Owners' Group EOP's does not address the S/G overfill issue but it does contain instructions for coping with a SG secondary side depressurization coupled with a failed tube and will be used in making this evaluation.

4.2.13 Termination of Letdown Relief

The rupture disc on the pressurizer relief tank (PRT) was blown because of an excessive accumulation of water, primarily from a failure to take timely operator action to isolate the letdown orifice value (AOV-200B).

The valve shut initially when its air supply was lost because the containment isolation signal shut the instrument air supply to the containment. When the containment isolation signal was reset and the air supply restored, AOV-200B

re-opened automatically and pressurized the downstream piping so that relief valve RV-203 lifted to relieve the pressure to the PRT (Fig. 6.8).

Rupture of the disc was avoidable by placing the control switch for the letdown orifice valve (AOV 200B) in the closed position when the valve closed on loss of instrument air, or by shutting AOV-200B when the following pressurizer relief tank indications and alarms were presented in the control room:

- high pressure alarm at 10:09 a.m.
- high temperature alarm at 10:10 a.m.
- high level alarm at 10:26 a.m.
- pressure 50.5 psig at 10:31 a.m.
- level 90% at 10:45 a.m.

Because of the prolonged relief period, the reactor coolant system lost inventory that had to be replaced during the period when fluid loss was also occurring through the ruptured tube. The excess water flowed through the rupture disc and was collected in the sump.

A containment isolation signal has been provided to letdown stream valves LCV-427, AOV-200A, AOV-200B, and AOV-202 to correct this problem and is discussed further in section 6.4. The staff finds this action to be acceptable.

4.2.14 Indicator Lights Burned Out

Numerous indicator lights on the control room consoles were found to be burned out by the NRC Task Force and were reported in NUREG-0909 (Reference 4.1). This precluded an expeditious determination of equipment status. Light indicators, both legend (annotations on the light cover) and nonlegend, have a multitude of applications in the Ginna control room. Bulbs were found burned out on both

BEST DOCUMENT AVAILABL

legend and nonlegend indicators. Since most nonlegend lights use a single bulb, the indication was not available when the bulb was burned out.

In addition, not all the bulbs were equally bright; the legend lights with dimmer bulbs were difficult to read. Apparently, the light intensity of bulbs was related to age. If indicator lights are to be used to provide safety system status information, they must operate properly.

The licensee has implemented administrative procedures that require a check, on a per shift basis, of all indicator light bulbs in the control room except those which can only be tested by operating equipment (such as breaker controls). Failed bulbs must be replaced immediately.

As part of the long term detailed control room design review required by the TMI Action Plan, a survey will be conducted to determine the number of bulbs which can be power tested (e.g., "push-to-test"), have dual filaments, are long-life qualified, or are operated with reduced voltage. Furthermore, the licensee will conduct a study to determine what hardware changes can be made to accomplish a more reliable indicator light system and a more effective and efficient test capability.

4.2.15 Terminology Problems on Control Panels and in Procedures

Several examples of inconsistent use of terminology on the control panels and between the panels and the plant procedures were observed during the review of the SGTR event. The use of terms and abbreviations in the control room and in procedur was inconsistent. For example, it was observed that steam generator appeared as STEAM GEN, STM GEN, and S/G. In addition, terminology appearing on the panels was inconsistent with that appearing in procedures and both appeared to be inconsistent with some commonly used terms. For example, the commonly used term "PORV Block Valve" appears on the control panel label as "PRESSURIZER REL. STOP VLV," and is referred to in the Steam Generator Tube Rupture procedure E-1.4, as "PORV backup isolation valve." This type of inconsistency causes confusion and may lead to operator error.

As part of the long term detailed control room design review, all terminology used in the control room will be reviewed against human factors guidelines for consistency of terms, acronyms and abbreviations, and the labelling will be modified accordingly. Furthermore, procedures will be modified to reflect consistency with the modified terminology.

4.2.16 Simulator Training

The operators indicated during staff interviews that during their training on a simulator, the simulators responded in a manner similar to the actual event, but at a slower rate. This is thought to be due to the fact that the Ginna plant has fewer steam generators than the facility which is modeled by the simulator. This raises a question on adequacy of the simulators response and on training programs for this event.

The staff has reviewed this question and has determined that, since the simulator responded satifactorily, albeit at a slower rate and since the objective of the training program is to develop an understanding of plant response under various accident scenarios, and since personnel understood the objectives and procedures for the event, based on their simulator training, the simulator used for training was adequate for operator training. The staff does recommend that the licensee review the simulators time response for this type of accident and take actions as necessary to emphasize the differences between the simulator and the plant in operator training sessions. The licensee has committed to modify his training plan as necessary to reflect this difference.

4.2.17 Procedure Deviations

During interviews conducted by the NRC staff following the SGTR event, operators stated that they did not deviate from approved procedures while coping with the event. These interviews were conducted within days after the event and operators were interviewed individually. The operators were not confronted with the actions which were later determined by the staff to be deviations and asked their views on each, since all of the deviations had not been identified. Further, the operators were receiving instructions through their supervisors

from the Technical Support Center, which has the authority when several of the individuals present there assemble as the Plant Operation Review Committee, to change procedures and authorize their use. Thus, the operators considered that the actions they performed had been approved and authorized. The NRC staff later determined that some of the instructions that were given to supervisors, and then to the operators, and some of the actions called for in procedures that were delayed were not in conformance with procedures.

The staff believes that when actions are covered in procedures, the prescribed actions are expected to be followed. When the event deviates from expectations, a reasoned and considered approach to cope with the contingency should be developed. It is expected that the method developed will be presented to management and authorization for the prescribed actions will be obtained, unless immediate action is required to protect the health and safety of the public.

The emergency procedures covering this event were used early in the event and, in general, followed step-by-step. The actions that NRC staff identified that deviated from approved procedures were the following:

(1) Starting one charging pump in preparation for reactor coolant system to B steam generator pressure equalization instead of starting all charging pumps, as discussed in the procedure E-1.4.

(2) After meeting the criteria for securing the safety injection pumps, plant staff delayed this action. A review of plant parameters had demonstrated adequate core cooling and natural circulation. The plant staff was unsure of the consequences of securing the safety injection pumps, but recognized that continued operation would lead to B steam generator safety valve openings. Safety injection pumps were subsequently secured and plant parameters were monitored to verify continued core cooling.

(3) Securing the condensate pumps which made the turbine condenser unavailable for the condenser steam dumps. The condensate pumps were secured to

BEST DOCUMENT AVAILABLE

prevent further contamination of the condensate full-flow demineralizers with radioactive water. The procedure did not consider a cooldown without the use of the condenser when offsite power is available.

(4) Restarting of a safety injection pump as a prerequisite for starting a reactor coolant pump was not discussed in Procedure E-1.4, but was done because normal pressure control had not been reestablished. The pump was started to minimize the pressure transient which would occur during the starting of a reactor coolant pump. The operating safety injection pump caused two subsequent lifts of the B steam generator safety valve.

(5) During the initial stages of the event, the Plant Superintendent directed the Operations Engineer to remain in the control room instead of reporting to the Technical Support Center as required by the site's Emergency Plan Implementing Procedures. This decision was based on a planned procedural improvement developed as a result of an earlier drill.

These deviations are discussed in detail in Sections 4.2.4, 4.2.7, 4.2.8, and 4.2.1.2 of this evaluation.

4.3 Conclusions

The staff has evaluated the adequacy of the operators' response to the steam generator tube rupture event, the written procedures invoked by operators, and the subsequent short term and long term procedural modifications proposed by the licensee.

The staff evaluation has determined that the operators' response and the written procedures used for mitigation of the event, to a large degree were consistent with the predicted and accepted guidelines on which operator training and procedures were based. The significant deviations from the procedures by plant personnel were consciously made following a study of their consequences before execution. These actions did not exacerbate the event. Subsequent review of the deviations has resulted in short term and long term modifications and further study by the licensee.

The licensee has made several commitments regarding future areas of study. The suggestions for pump trip and restart have already been discussed. The other study areas relate to cooldown of a faulted generator, coping with a vessel steam bubble, and additional natural circulation cooldown guidance. All of these areas have been previously discussed with the staff and owners groups. In the judgment of the staff, they need not be resolved before startup but should be resolved within approximately six months.

Therefore, based on an evaluation of the licensee's response to the event and the subsequent program for further improvements, the staff has concluded that adequate protection is provided for steam generator tube rupture events.

4.4 References

4.1 NUREG-0909, "NRC Report on the January 25, 1982 Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant," U.S. Nuclear Regulatory Commission, April 1982

4.2 Letter from J. E. Maier to NRC dated May 4, 1982

4.3 Final Design Safety Analysis, R. E. Ginna Nuclear Power Plant, Docket 50-244

BEST DOCUMENT AVAILABLE

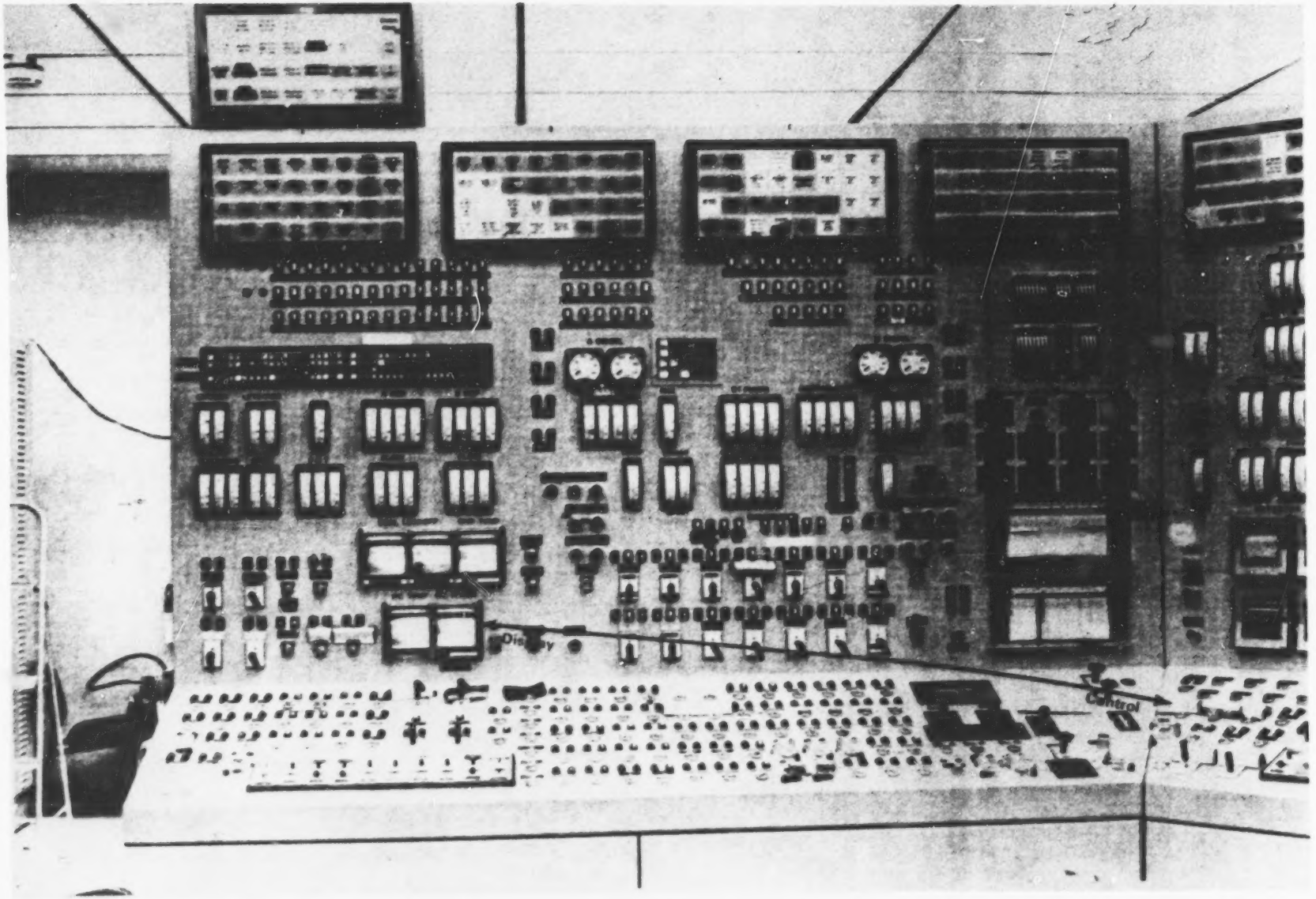


Figure 4.1 Power operated relief valve control and display-old relationship

BEST DOCUMENT AVAILABLE

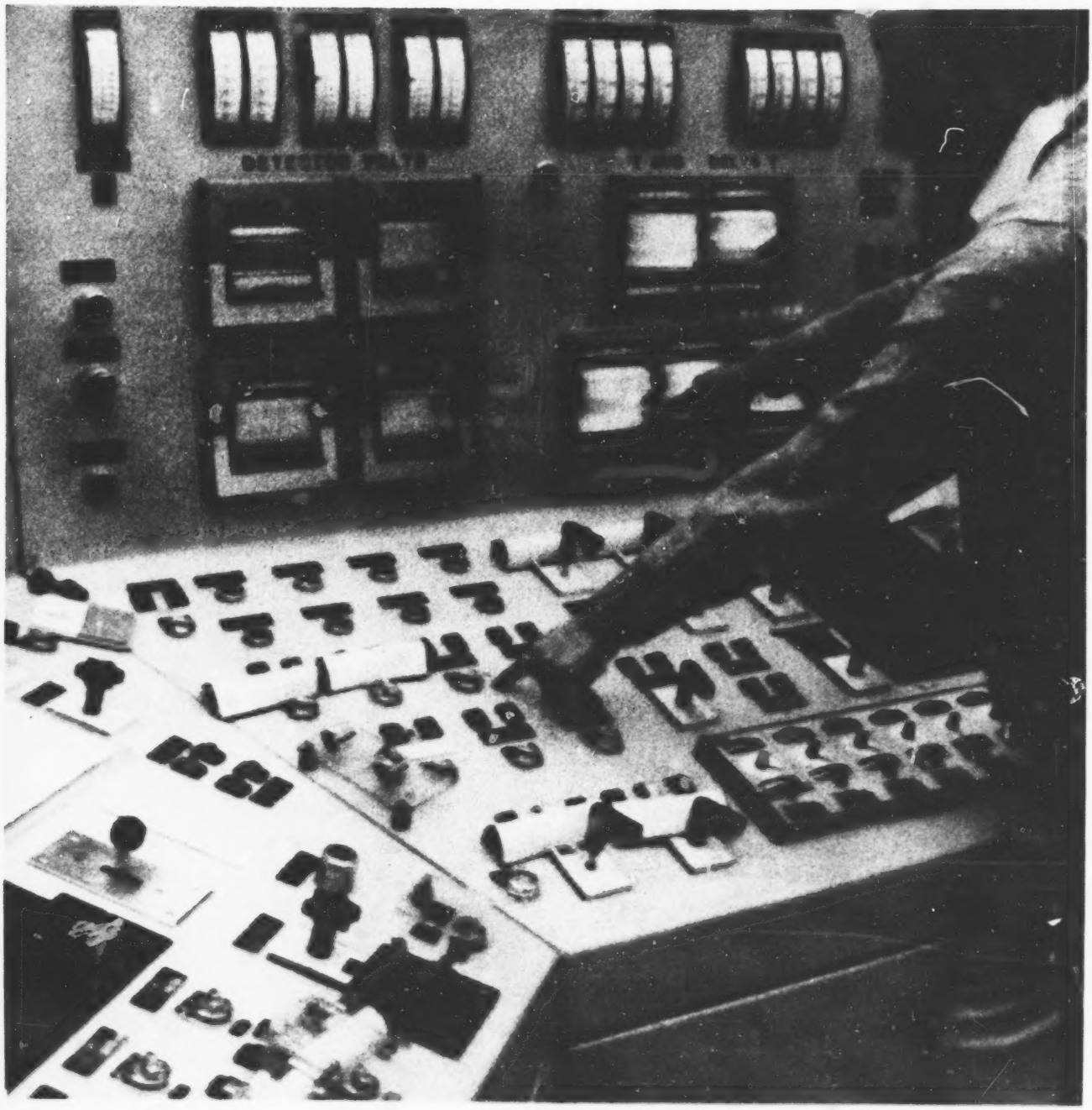


Figure 4.2 Power operated relief valve control and display-new relationship

5.0 STEAM GENERATOR INSPECTION PROGRAM, FAILURE ANALYSIS, AND REPAIRS

5.1 Summary

Investigations performed subsequent to the steam generator tube failure revealed the immediate cause of the failure to be excessive thinning of the tube wall leading to a pressure burst of the tube. The ruptured tube was located in the hot-leg of B-steam generator three rows inboard of the tube bundle periphery (See Figure 5.5). Numerous tubes in the peripheral region, including the outer two rows of tubes immediately adjacent to the tube which ruptured, had been plugged beginning in 1976, as a result of eddy current indications found during inservice inspection of these tubes or as the result of small primary-to-secondary leaks.

Visual inspections using television and fiber optic techniques revealed localized extensive damage to previously plugged tubes in the peripheral area. Numerous foreign objects and pieces of broken steam generator tubing have been found in the annular region between the tube bundle and the shell. Most of the foreign objects are believed to have been introduced during steam generator modifications performed during periods dating back to 1975.

The largest foreign object found, acting in conjunction with normal thermal and hydraulic loadings, is postulated to have initiated a sequence of events which led to the plugging of many tubes at or near the periphery, and eventually to the tube rupture. The wall thinning which led to the rupture is postulated to have occurred as a result of contact wear with an adjacent tube which had previously been plugged and which subsequently severed.

The licensee has performed an extensive investigation of the extent of tube degradation in the Ginna steam generators and the failure mechanism(s). Based upon the results of this investigation, the licensee is performing a number of repairs and modifications to eliminate the conditions which caused the failure. This includes the removal from the steam generators of all foreign objects and

previously plugged tubes which are sufficiently degraded and could potentially cause degradation of adjacent tubes. In addition, the licensee has proposed a number of actions to be performed prior to and subsequent to restart from the current outage to verify that the conditions for future tube failures due to this phenomenon have been eliminated.

5.2 Steam Generator Design, Surveillance Requirements, and Operating History

5.2.1 Steam Generator Design

The Ginna plant is a two-loop pressurized water reactor system with one Westinghouse Model 44 (44,000 ft^2) vertical U-tube steam generator per reactor coolant loop. The steam generators were fabricated by the Westinghouse Heat Transfer Division and are similar to those at H.B. Robinson, Point Beach Unit 1 and 2, Indian Point Unit 2, and the original steam generators at Turkey Point Units 3 and 4.

Figure 5.1 shows a cutaway view of this type of steam generator. The primary channel head, the tubesheet, and the 3,260 U-tubes form the reactor coolant pressure boundary within the steam generator. Feedwater enters the secondary side of the steam generator through an inlet nozzle and internal feed ring. The preheated water flows down the space formed by the tube wrapper and the shell (the downcomer annulus), and then flows between the end of the wrapper and the tubesheet into the tube bundle. The U-tubes provide the surface area needed to transfer heat from the primary system to the secondary system.

Moisture separators and dryers are located above the tube bundle. These components function to improve steam quality by removing entrained moisture from the steam leaving the tube bundle. The moisture removed from the steam is recycled through the downcomer annulus for mixture with the incoming feedwater.

Components significant to the discussion that follows in this report are the tubes and tube bundle, the tubesheet, the tube support plates, the downcomer flow-resistance plate, the tube bundle wrapper, the stub barrel, and the shell.

The tubes of each steam generator are 7/8 in. in diameter with a 0.050 in. thick wall, and are made of a nickel-chromium-iron alloy (Inconel 600). The tubes were rolled and welded to the tubesheet, but were not expanded in the tubesheet beyond the length expanded in shop fabrication.

The tubesheet is a 22 in. thick, low-alloy steel forging that is clad with a nickel-chromium-iron alloy and has holes drilled to accept the U-tubes. The tubesheet is welded to the stub barrel section of the shell.

Carbon steel drilled tube support plates are spaced throughout the axial length of the vertical sections of the tube bundle and are numbered sequentially, starting from the first support above the tubesheet. These plates provide lateral support to the tube bundle. The tube support plates are attached to the wrapper by means of wedges, which are welded to the wrapper and to each support plate (See figure 5.2). Around the periphery of each support plate are 12 equally spaced wedge location areas, six on the hot-leg side and six on the cold-leg side. Only half of these areas on each individual plate are used to support the plate. For the first and odd-numbered tube support plates, wedge areas 2, 4, 6, 8, 10, and 12 are the locations where the tube support plate is affixed to the wrapper. Wedge areas 1, 3, 5, 7, 9, and 11 are affixed to the wrappers for the even-numbered tube support plates. The wedge areas are strengthened by the absence of the flow holes that normally surround each tube.

The shell is made of low-alloy steel plate. It forms the outer boundary of the downcomer annulus and provides support for the upper internals of the generator.

5.2.2 Secondary Side Modifications

In March 1975, modifications were made to the steam generators to increase lateral flow velocities across the tubesheet and to improve blowdown efficiency. The purpose of the increased flow velocity and blowdown was to reduce the amount of sludge that had accumulated on the tubesheet. The sludge provided the concentrating medium where corrosion of the tubing had been observed. These modifications included removal of the downcomer flow

resistance plates by oxyacetylene cutting, modifications to the feedring, replacement of the moisture separator orifice rings, and installation of blowdown lane flow blockers.

Additional modifications to the moisture separators were made in February 1976 to reduce moisture carryover. In February 1979, the bottom drain holes on the feedring were plug welded and J-tubes were installed on top of the feedring to provide added assurance against water hammer.

5.2.3 Steam Generator Operating Environment

The Ginna steam generator began operation in 1970 with coordinated phosphate ($NaPO_4$) secondary water chemistry control to reduce corrosion and continued on this regime until 1974. During this period the industry in general experienced early difficulties with phosphate wastage corrosion and stress corrosion cracking where sludge had accumulated on the tubesheet. These difficulties were attributed to problems in adequately controlling phosphate concentrations and to impurities carried into the steam generators by the feedwater.

Wastage corrosion was identified during inservice inspections performed at Ginna in Spring 1974. Following a Westinghouse recommendation to its customers in September 1974, Ginna converted from phosphate to all-volatile treatment (AVT) secondary water chemistry control during a shutdown which began in November 1974. AVT consisted of the addition of hydrazine (N_2H_4) to the condensate water for the purpose of scavenging oxygen. At this time, blowdown rates were increased from the maximum of 16 gallons per minute (gpm) per steam generator to 64 gpm to reduce cation conductivity.

The licensee reports that it has closly monitored condenser tube integrity and performed preventive repairs to damaged condenser tubing during shutdowns to provide assurance of feedwater purity. In addition, full-flow polishing demineralizers were installed and have been in service since 1978. Blowdown rates were further increased to 70 gpm in February 1979.

The following blowdown chemistry comparison demonstrates the continued improvement in bulk water chemistry over the last eight years:

Parameter	1974-1977	1978	1981
Cation Cond., μmhos	0.7-2.5	0.2-0.4	0.12-0.2
Chloride, ppb	<50	<10	3-5
Sodium, ppb	5-15	5-15	3-8
Silica, ppb	20-50	15-30	5-10
pH	8.6-9.0	8.7-8.9	8.7-8.9

Since November 1969, oxygen concentration has generally been less than 5 parts per billion (ppb). There have been several times over the last twelve years when dissolved oxygen has been as high as 40 ppb for several days. From July 1978 to the present, feedwater dissolved oxygen has been less than one (1) ppb.

5.2.4 Steam Generator Surveillance and Repair Requirements

Pressurized water reactor steam generators supplied by the various nuclear steam supply system vendors have, over a number of years, experienced a variety of tube-degradation problems. The problems have included degradation caused by tube corrosion, vibration, mechanical wear or impact, or the phenomenon knows as "denting." These mechanisms have been discussed in detail in NURG-0886 (Ref. 5.2). To provide assurance that PWR steam generators can be operated safely, the primary objective of the NRC has been that degraded steam generator tubes retain adequate integrity against a gross tube failure or burst over the full range of normal and postulated accident conditions. To meet this objective, steam generator tube surveillance requirements have been established. These include requirements for inservice inspection of steam generator tubes, acceptance criteria beyond which degraded steam generator tubes must be removed from service by plugging or repaired by sleeving, and primary to secondary leakage rate limits beyond which the plant must be shutdown for appropriate corrective action.

5.2.4.1 Inservice Inspection Requirements for Steam Generator Tubing

Appendix B of the Ginna Station Quality Assurance Manual presents the licensee's inservice inspection program. This document commits to the requirements of Title 10, Section 50.55a of the Code of Federal Regulations and follows the guidance of Section XI of the ASME Code. The selection of steam generator tubes for examinations and the extent of these examinations are as described in NRC Regulatory Guide 1.83, Revision 1, dated 1975.

Plants currently undergoing review for an operating license are required by the staff to incorporate a steam generator inspection program into the plant Technical Specifications which complies with the Standard Technical Specifications for Westinghouse Pressurized Water Reactors, NUREG-0412, Revision 2, in addition to Regulatory Guide 1.83. The Standard Technical Specifications contain more stringent tube sampling requirements (i.e., number of tubes to be inspected) than Regulatory Guide 1.83 for cases where initial sampling inspection results in the finding of a certain number of degraded or defective tubes. However, the sample sizes actually implemented for steam generator inspections at Ginna in recent years have generally met or exceeded the Standard Technical Specifications. Steam generator inspection programs implemented at Ginna since April 1980 have included 100% sampling of tubes on the hot-leg side, and at least a 25% sample on the cold-leg side.

Eddy current testing (ECT) is the principal method used for performing tube inspections. This inspection method involves the insertion of a test coil inside the tube that traverses the tube length. The test coil is excited by alternating current, which creates a magnetic field that induces eddy currents in the tube wall. Disturbances of the eddy currents caused by flaws in the tube wall will produce corresponding changes in the electrical impedance as seen at the test coil terminals. Instruments are used to translate these changes in test coil impedance into output voltages which can be monitored by the test operator. The depth of the flaw can be determined by the observed phase angle response. The test equipment is calibrated using tube specimens containing artificially induced flaws of known depth.

BEST DOCUMENT AVAILABL

Eddy-current examination of steam generator tubes is currently conducted in accordance with the licensee's Procedure NDE-500-4, Revision 4. This procedure utilizes standard Zetec bobbin-type coil probes, a Zetec Vector Phase analyzer with an integral series 5103N two-channel storage-display oscilloscope, a Hewlett Packard/Zetec HP3968AZ magnetic-tape recorder, and two Gould 220 brush strip-chart recorders.

Single-frequency differential coil techniques were employed for eddy current examination until April 1978. In April 1978, multifrequency differential coil techniques using the newly developed French equipment were instituted. Starting in April 1980, Zetec multifrequency differential and absolute coil techniques were used. The use of multifrequency eddy current techniques, as opposed to single frequency techniques, has resulted in enhanced operator capability to discriminate small amplitude defect signals from such sources as the tube support plates and tubesheet.

The RG&E inspection uses 200 and 400 kHz differential, 100 kHz absolute (which are the normal measurements made for multiple-frequency tests), and 210 kHz absolute. The mix of the 200 and 400 kHz differential signals allows the tube-sheet and tube support plate signals to be eliminated from the differential channel. In addition, a mix of the 100 and 210 kHz absolute channels gives an absolute measurement of the wall thickness without the presence of the tube support and tubesheet signals. This additional absolute mix data channel is in excess of both the Section XI requirements and the normal commercial practice for multiple-frequency eddy-current testing being performed at other nuclear power plants. It is the staffs conclusion that the inspection techniques used at Ginna meet or exceed ASME Code requirements and conform to the state of the art.

5.2.4.2 Plugging Limits

Appendix B of the Ginna inservice inspection program establishes the bases for interpretation of the eddy current inspection results and specifies a 40% limit on allowable percent through-wall penetration by tube flaws (such as corrosion or mechanical wear). The 40% plugging limit is intended to assure

that tubes accepted for continued service will retain adequate structural margins against a gross tube failure under normal operating and accident conditions. Tubes exhibiting eddy current indications in excess of this limit must be plugged or repaired by sleeving (sleeving is discussed in Section 5.2.4.3). The plugging repair procedure involves the insertion of plugs at the inlet and outlet ends of the tube, rendering the tube inactive as a primary pressure or heat transfer boundary.

5.2.4.3 Sleeve Repairs

Sleeving has been approved on a limited basis (maximum of 25 tubes per SG per inspection) at Ginna as an alternative to plugging. A sleeve repair involves the insertion of smaller diameter tubes (sleeves) inside the parent tube so as to span the degraded portion of the parent tube and then sealing the sleeve ends against the tube wall. Sleeves are designed to restore the original integrity of the degraded tube, while allowing the tube to remain functional.

A total of 21 sleeves have been installed on the B-steam generator to repair tubes in the central bundle region affected by tubesheet crevice corrosion. Neither sleeving nor tubesheet crevice corrosion was a factor in the tube rupture occurrence on January 25, 1982.

5.2.4.4 Primary to Secondary Leakage Rate Limits

PWR operating experience has demonstrated that in the vast majority of instances where degradation has developed completely (100%) through-wall, the resulting leakage has been small. The Ginna Technical Specifications limit the allowable primary-to-secondary leakage to 0.1 gpm. This limit is intended to ensure that in the event that leaks occur, the plant will be shutdown before the tube becomes sufficiently degraded such that a gross tube failure can occur during normal operation or postulated accident conditions.

5.2.5 History of Steam Generator Tube Degradation Problems at Ginna

Ginna has experienced a variety of steam generator tube degradation problems since initial startup in 1970. A historical summary of tube plugging based on eddy current test results is given in Tables 5.2-1 and 5.2-2 for steam generators A and B, respectively. Figures 5.3 and 5.4 illustrate the pattern of plugging across the steam generator A and B tube bundle cross-sections. With the exception of tube degradation at the periphery of the hot-leg in B-steam generator, tube degradation experience has been similar to that at other Westinghouse steam generators which began operation prior to mid-1970's with phosphate secondary water chemistry control. These problems have included wastage corrosion, stress corrosion cracking (SCC), and general intergranular attack (IGA) all of which have occurred in the interior of the tube bundle where sludge has accumulated on the tubesheet. Minor denting (squeezing of the tube as the result of corrosion product buildup in the tube/tube support plate annulus) has also been observed.

Wastage and stress corrosion cracking above the tubesheet have been essentially inactive since April 1977 following conversion from phosphate to all-volatile chemistry control in December 1974. Since February 1980, IGA and SCC have been detected in the interior region of the B steam generator tube bundle in the narrow crevices which exist between the tubes and tubesheet. This tubesheet crevice phenomenon has been attributed to the presence of free caustics in the crevices for which previous operation with phosphate control appears to have been a major contributing factor. The licensee has been employing a cyclic treatment which involves soaking, heatup, pressurization, and depressurization of the secondary side of the steam generator to produce a boil out and reduction in contaminants in the tube sheet crevices.

Beginning in 1976, numerous tubes have been plugged in the peripheral region of B-steam generator on the hot-leg side. These tubes were plugged as a result of eddy current indications interpreted as either ID (inside diameter) initiated or OD (outside diameter) initiated indications or as a result of small leaks (0.1 gpm). These defects occurred mainly in the wedge areas (areas where the support plates are attached to the shell of the steam generators)

Table 5.2-1 Ginna Station A-Steam Generator Tube Plugging History

Date	Wastage	SCC*	Pitting	Manuf.	TOTAL
In Factory				1	1
March 1974	19				19
November 1974	2				2
March 1975		46**			46
February 1976	39				39
April 1977	13				13
April 1978			1		1
April 1980			1		1
	73	46	2	1	122

*SCC (caustic stress corrosion cracking)
**one tube leak of less than 0.1 gallons per minute

Table 5.2-2 Ginna Station B-Steam Generator Tube Plugging History

Date	Wastage	SCC+	IGA++	Periphery	TOTAL
March 1975		11			11
January 1976	(2)*			(2)	2
February 1976	2				2
April 1976				15*	15
April 1977	1				1
July 1977	1			5*	6
January 1978	6			2*	8
April 1978				15	15
February 1979	2		2	2	6
December 1979			11	2*	13
April 1980	1		31**	2	34
November 1980			3**		3
May 1981			14**	1	15
January 1982			13	3***	16
TOTALS	15	11	74**	49	147

(2)these 2 tubes were wastage indications below the top of the tube sheet on the periphery

*a total of 5 tube leaks less than 0.1 gallons per minute

**28 tubes of 74 were not above plugging limit of 40% wall penetration but were plugged nevertheless

***R42C55 tube rupture

+SCC (caustic stress corrosion cracking)

++IGA (tube sheet crevice intergranular attack of the tubes)

usually within the first four inches above the tubesheet. However, 2 tubes were found with indications approximately 24 inches above the tubesheet.

This peripheral pattern of tube degradation is not typical of the corrosion problems which have been experienced by the industry. Secondary side corrosion of the tube wall generally occurs in the interior of the bundle where sludge (which provides a concentration medium for corrosion) has accumulated on the tubesheet. Industry problems with primary side corrosion have been limited to Coriou ("pure water") stress corrosion cracking at regions of high stress such as tube support locations where denting has occurred and in the U-bends. Primary side Coriou cracking has not been reported by the industry to have occurred between the tubesheet and first support plate.

A peripheral tube, Row 45 Column 52, (R45 C52) was removed from the steam generator in April 1978 for laboratory examination. This tube contained eddy current indications which were interpreted as small ID initial signals and a possible bulge. The field eddy current indications for this tube were similar to those which had previously been recorded for another peripheral tube, and leakage had later developed in that tube. Examination of the pulled tube specimen performed by Westinghouse under EPRI sponsorship revealed a number of anomalies in the outer diameter appearance which are described in additional detail in Section 5.4.2 of this report, but no evidence of any ID cracking. Based upon the examinations performed, the investigators were unable to make any conclusion regarding the nature or cause of the degradation which has led to leaks in other peripheral tubes (Reference 5.3).

5.3 STEAM GENERATOR INSPECTIONS FOLLOWING RUPTURE OCCURRENCE

5.3.1 Eddy Current Inspections

5.3.1.1 Inspection Scope and Results

Hydrostatic leak testing performed subsequent to the rupture occurrence identified tube R42 C55 in the hot-leg of B-steam generator as the ruptured tube. The tube that failed was immediately adjacent to three tubes that were

previously plugged in row 43 (see Figure 5.5). No other leaking tubes were found. Eddy current inspection of this tube confirmed the presence of a large volume defect 5 inches in length extending 3 to 8 inches above the tubesheet. Fiber optic examination of the inside of the tube confirmed a diamond shaped ("fishmouth") axial tube rupture approximately 5 inches long and 0.75 inches wide at its center (see Fig. 5.6). This tube was removed from the steam generator for further study. Subsequent visual and metallurgical inspection (described further in Section 5.4.4) revealed that the tube wall had been thinned by a wear process over an approximately 6 inch length,causing a weakening of the tube and eventual rupture of the tube under the normal operating 1450 psi primary to secondary pressure differential.

Both steam generators were eddy current inspected following the rupture occurrence. All tubes in both steam generators were subjected to at least a partial length inspection up to at least the first tube support plate on the hot-leg side. This encompasses the region where the peripheral tube degradation phenomenon has been observed in recent years as well as the region where tubesheet crevice corrosion has or would be expected to occur. Additional lengths of tubing were inspected outside the region to determine whether there may be other problem areas in the steam generators. This included taking an 8% tube inspection sample through u-bends from the hot leg side in steam generator B, and at least a 3% sample in both steam generator from tube-end to tube-end. Additionally, all tubes within two rows of the periphery on the cold-leg side were sampled to the first support plate.

All indications found were located in the hot-leg side of B steam generator below the first support elevation where a 100% inspection sample had been performed. Two tubes at the periphery were found with OD indications approximately 24 inches above the tubesheet as follows:

R45 C46	41% of tube wall
R45 C47	49% of tube wall

BEST DOCUMENT AVAILABLE

Except for the ruptured tube, no other indications were found in the peripheral region. However, in addition to the two tubes above and the ruptured tube, three tubes immediately adjacent to the ruptured tube were also plugged as a precautionary measure.

In the interior of the bundle, 13 tubes as identified below had tubesheet crevice indications similar to the crevice indications of IGS and SCC of which have been observed in previous inspections. All thirteen tubes were plugged.

1. R9 C44 - 14 inches below the top of the tube sheet (TTS)
2. R16 C42 - 12 to 14 inches below TTS
3. R18 C39 - 4 to 12 inches below TTS
4. R20 C45 - 10 inches below TTS
5. R20 C44 - 10 inches below TTS
6. R21 C56 - 10 inches below TTS
7. R21 C43 - 4-12 inches below TTS
8. R24 C56 - 4 inches below TTS
9. R24 C48 - 6-10 inches below TTS
10. R33 C59 - 17 inches below TTS to rolled transition
11. R35 C54 - 16 inches below TTS to rolled transition
12. R35 C53 - 12 inches below TTS to rolled transition
13. R35 C40 - 16 inches below TTS to rolled transition

Figure 5.5 updates the tube plugging map for B-steam generator as a result of these inspections.

Based upon the staff review of the eddy current inspection samples taken and the results obtained, the staff finds that the inspection program was adequate in scope to define any problem areas, and that 100% sampling of these problem or potential problem areas has been performed.

5.3.1.2 Ruptured Tube Eddy Current Data Review

The ruptured tube had previously been eddy current inspected in April 1981, but no indication had been recorded for this tube. A re-review of the eddy current

data tapes from the April 1981 inspection indicated that the ruptured tube exhibited no differential coil signal but did indicate a 4-inch long absolute coil signal estimated with the calibration standards utilized to represent a 20% outer surface metal loss indication. The calibration standards employed included a defect standard with round flat bottomed holes of varying depth and diameter, as required by Section XI of the ASME Code.

For wear or uniform thinning type flaws (as opposed to abrupt or sharp flaws which vary gradually over the length of the tube) the differential mode inspection may not detect a significant difference between the two test coil signals, and thus no differential signal will be produced.

By looking at the magnitude of the absolute signal (either 100 or 210 kHz), this type of signal can be detected, even if there is no signal on the differential channels. This has been verified using a fretting or wear standard with 20, 40 and 60% of the wall removed which was constructed in response to the suggestion of an NRC staff consultant on eddy current test techniques who was at the site. Use of this kind of standard is not a requirement by the ASME Code or the licensee's test procedure. When this wear standard is employed, the absolute indication obtained for the ruptured tube in April 1981 is interpretable as slightly greater than a 40% through wall defect rather than the 20% indication as interpreted from the ASME Code standards. However, there is no way to interpret a given signal as a fretting or wear signal as opposed to a 360° uniform thinning signal 100% of the time using the standard bobbin type eddy current probe. Also, if the fretting standard is used as the plugging standard, some tubes with small uniform thinning flaws may be needlessly plugged.

The NRC staff consultant at the site also reviewed the eddy current data from the April 1981 inspection for tube R43 C53 which was plugged at that time as a result of an indication interpreted as an 80% through wall indication. This test was performed using the 100 and 210 kHz absolute and the 200 and 400 kHz differential. The absolute signals from this tube are not exactly the same as either tube R42 C55 or the fretting standard, but were somewhat similar. Using an extrapolation of the fretting standard results would give a depth of 85% for

this defect. The axial length of the indication along the wall was about 2 inches. This shorter length and greater depth resulted in sharper variations in the wall thickness, which produced a 400 kHz differential signal. This resulted in the tube being recognized as defective and plugged.

As previously discussed, only three tubes in the peripheral region, including the ruptured tube, were found with eddy current indications of any kind (either in the differential or absolute mode), and these tubes have been plugged. The NRC staff consultant at the site reviewed the eddy current data from the current outage for a number of tubes including the three tubes immediately adjacent to the ruptured tube (i.e., R42 C56, R41 C55, and R42 C54), and concurred with the licensee's finding that these tubes were free of indications between the tube and the first tube support plate.

5.3.2 Fiber Optic and Television Inspections

As part of the inspection program, fiber optics inspections were performed from the secondary side in B-steam generator. Abnormal damage to previously plugged tubes at the periphery and a large foreign object were observed as the inspection proceeded around the periphery of the bundle from the handhole entry through the shell. Because of these results, the licensee deemed it was necessary to perform further inspections utilizing video equipment and procedures with the capability of a greater field of vision and higher resolution of peripheral tubes.

Subsequently, a remotely controlled TV method was utilized in both steam generators using a standard Westinghouse Electric Corporation underwater reactor vessel camera, Model ETV 1250. The video inspection consisted of scanning the peripheral tubes around the total circumference of the steam generator hot and cold legs and then scanning the tube columns perpendicular to the tubesheet blowdown lane. The data obtained was videotaped. The TV examination indicated severe damage to previously plugged peripheral tubes, particularly in the number 4 and number 6 wedge areas, and identified foreign objects and loose pieces of tubes in the peripheral area. The damage observed included tubes with large holes, tubes with longitudinal and circumferential fractures,

tubes completely severed at the top of the tubesheet, tubes with dents, and tubes plastically deformed sufficiently to be classified as collapsed. In addition, some minor scrapes and dings (localized indentations on the surface of the tube) were identified on tubes located near R40 C68. Details of the anomalous findings from these visual inspections are summarized in Table 5.3-1.

As previously mentioned, the TV examination identified the existence of foreign objects on the tubesheet. The largest object found in the B-steam generator was a plate that had the dimensional characteristics of a portion of the downcomer flow resistance plate which had been cut out and removed in 1975. This foreign object is approximately pieshaped, as shown in Figure 5.7. The size is roughly 4.13 in. x 6.5 in. x 0.5 in. thick. The material is magnetic and has the appearance of carbon steel plate. The edges appear to be flame cut. On one side there is a portion of a hole of the same diameter as the orifice holes in the downcomer flow resistance plate. The plate contains a raised section which appears to be a portion of the fillet welded stiffener that was attached to the flow-resistance plate. Visual examination of the surface of the foreign object shows two parallel grooves in the plate whose curvature and center-to-center spacing is similar to the tube bundle spacing. Other objects of smaller dimensions, but appearing to be of similar material were found in other locations on the tubesheet, including one object found on the cold-leg side. In addition, parts of fractured tubes and tube fragments were found.

The following is a listing of foreign objects and loose parts found in the B-steam generator:

(a) Piece of magnetic carbon steel plate 0.5 inches thick by 4.18 inches wide by 6.31 inches long. Located near R25 C85 area.

(b) Piece of magnetic carbon steel plate 0.5 inches thick by 1.5 inches wide by 1.5 inches wide by 3.5 inches long. Initially located near R45 C46 area.

BEST DOCUMENT AVAILABLE

Table 5.3-1 Results of TV Optics Examination in the B Steam Generator

Tube (Row Column)	Licensee's Recorded Indication On Visual Examination	Tube Row Column	Licensee' Recorded Indication On Visual Examination
HOT LEG:			
R8C92	Collapsed plus a hole	R43C61	Severed at tubesheet
R10C91	Ripples on outer surface	R43C60	Outer surface scraped
R10C91	Outer surface wiped and scraped	R44C58	Collapsed
R11C91	Collapsed plus a hole	R44C56	Collapsed
R12C91	Collapsed plus a hole	R44C55	Collapsed
R13C90	Outer surface damage	R44C54	Collapsed
R14C90	Collapsed plus outer surface depression	R44C53	Collapsed
		R45C51	Ripples on outer surface
R15C90	Collapsed plus a hole	Near R43C34	Piece of wire
R16C89	Outer surface damage	Near R32C15	Piece of tube wedged between R32C15 and stay bar
R17C89			
Near R30C81	Piece of tube on tube-sheet		
R38C72	Outer surface damage	COLD LEG:	
R38C71	Outer surface damage	Near R33C67	Piece of tube on tube-sheet
R39C70	Outer surface damage		
R39C69	Outer surface damage	Near R40C25	Small square object on tubesheet, about 3/4" X 3/4", covered by sludge dust
R39C68	Outer surface damage		
R39C65	Dings		
R41C64	Dings		
R42C64	Dings		
R42C63	Dings	R5C1	Outer surface scraped
R42C62	Dings		

AVAILABLE

(c) Piece of magnetic carbon steel plate, oval shaped, 0.5 inches thick, minor axis 2.0 inches with major axis 2.375 inches. Located wedged between R45 C53 and R44 C53.

(d) Piece of magnetic carbon steel strip 0.050 inches thick by 0.6 inches wide by 4 inches long. Located near R25 C85 area.

(e) Piece of copper tubing, approximately 0.25 inches in diameter by 1.062 inches long. Located near R45 C47 area.

(f) Piece of welding electrode 0.18 inches in diameter by 2 inches long. Located near R43 C34 area.

(g) Four pieces of welding slag in small ball shapes less than 0.5 inches in diameter.

(h) Two pieces of material in small ball shapes less than 0.25 inches in diameter.

(i) Small pieces of Inconel tubing were also identified from damaged tubes of various lengths. These were located in the Number 4 wedge area. Two other pieces were identified, one near R30 C81 the other near R33 C15.

No foreign objects were found in the A steam generator hot-leg. The following foreign objects were found in the A steam generator cold-leg:

(a) A piece of wire 0.0375 inches in diameter, 11.1 inches long, non-magnetic, stainless steel located near R34C77.

(b) A piece of wire 0.1265 inches in diameter, 4.5 inches long, magnetic, carbon steel weld rod, located near R44C38.

(c) Piece of metal with portion of weld. Irregular shape approximately 0.5 inches thick by 0.75 inches wide by 1 inch long. Magnetic material, carbon steel plate segment. Located near R44 C38.

5.4 FAILURE ANALYSIS

5.4.1 Introduction

The licensee has performed an extensive failure analysis program to establish the cause of the peripheral tube degradation and the January 25 tube rupture occurrence as part of the basis for steam generator repairs and modifications (discussed in Section 5.5) to correct the problem prior to restart from the current outage. Elements of this failure analysis program included (1) metallurgical examinations of tubes (including the ruptured tube) which were removed from the steam generators, (2) review of eddy current data dating back to 1976 when indications were first observed, and (3) analyses and tests to verify the postulated failure mechanism.

The results of this failure analysis program have been reviewed in detail by the NRC staff and its consultants from Brookhaven National Laboratory, and Franklin Research Center. The consultant's findings are reported in Appendices A and B respectively. In addition, Brookhaven National Laboratory performed confirmatory metallurgical examinations for the NRC of several of the tube specimens which were removed from steam generator B.

5.4.2 Postulated Failure Mechanism - Summary

The following is postulated by both the licensee and the NRC staff to have been the likely sequence of events leading to the tube rupture occurrence on January 25, 1982 and is depicted graphically in Figure 5.8. The supporting bases for these findings are provided in the subsequent subsections of this report.

1. Foreign objects fell onto the tubesheet outside the periphery of the tube bundle during steam generator modifications performed in 1975 and during subsequent modifications.

2. Foreign objects impacted on exposed (outermost) peripheral tubes as a result of the high velocity flow in the peripheral area. The flow pattern

in the welded lug locations (wedge areas) appears to be such that the objects tended to lodge there rather than continue randomly around the downcomer annulus. Initial plugging of these tubes was performed as a result of eddy current indications and/or small primary-to-secondary leaks. For this reason tubes were plugged preferentially at these locations.

3. Foreign objects in conjunction with thermal, hydraulic, and pressure loadings caused continued damage to the plugged tubes on the periphery. This continued damage eventually caused the tubes to collapse and in some cases to become completely severed near the top of the tubesheet as a result of fatigue.

4. Once severed, the plugged tubes were free to vibrate over approximately a 50 in. span pivoting at the first support plate. The free end then interacted with adjacent tubes, including previously unplugged tubes located inboard of the outer row of tubes, resulting in a fretting type wear of these adjacent tubes. These tubes, in turn, were plugged as a result of eddy current indications or leaks; however, the damage mechanism continued to occur until these tubes also became severed.

5. Eventually, tube R42 C55 was subjected to fretting type wear over about a 6 inch length from an adjacent tube which had been plugged previously and which subsequently severed. The wear produced a detectable eddy current indication in April 1981 which was not interpreted at the time as a pluggable indication. Continued wear of this tube led to the tube burst. The wear occurred relatively uniformly over several inches of length such that local penetration of the wall and small leakage did not occur before the tube became sufficiently weakened so as to cause a rupture.

5.4.3 Overall Steam Generator Eddy Current Data

Table 5.4-1 summarizes the sequence of plugging in the peripheral region in B-steam generator, and the eddy current data interpretation at the time the tubes were plugged. Tube locations are illustrated in Figure 3.1.

The peripheral tubes in B-steam generator began exhibiting distress in the form of eddy current indications and small leaks dating back to January 1976. The largest foreign object (See Section 5.3.2) is believed to be a piece of the flow resistance plate which was not removed in March 1975, predating the indications of distress at the periphery.

Peripheral tubes which have been plugged tend to be concentrated in discrete batches around the periphery of the bundle; particularly the number 2, number 4 and number 6 wedge areas and near tube R39 C70. Initial plugging activity occurred first at the R39 C70 vicinity in February 1976, and then shifted to wedge areas number 2 and 6 during the May 1976 outage. From July 1977 to the present, the bulk of the plugging activity has been confined to the number 4 wedge area with some additional plugging activity in the vicinity of R39 C70 in February 1979. This pattern is consistent with a failure model which assumes a large foreign object as a necessary initiater of the peripheral tube degradation at a given location. Then the object moves away to affect another part of the periphery. Flow model testing by Westinghouse (Section 5.4.6) confirm that a foreign object of the same description as the largest object found in the steam generator would be mobile in the peripheral region tending to linger at the wedge area locations since these areas tend to be areas of relatively low flow. Initial distress at each of the affected areas of the periphery affected the outermost tubes only, which would be the only tubes which could be directly impacted by a large foreign object.

Eddy current indications for tubes located in the outermost row of tubes were generally interpreted as ID indications or bulges. An NRC staff consultant reviewed the recorded eddy current data for some of these tubes and concluded that these interpretations were reasonable, but not certain based on the available data. Examination of the tube pulled from the outer periphery in 1978 as a result of small ID and a bulge indication revealed no evidence ID cracking, but did reveal shallow peen-like marks and dings, irregular but shallow wall thinning, and ripples and local tube wall distortions including a bulge. Many of these features are suggestive of a mechanical or peening-like action on the surface of the tube such as might be cause by a foreign object. Similar peening-like markings were observed on tube surfaces following the

flow model tests where a foreign object was free to interact with the tubes. The analysts who examined the tube were unable to make any conclusion in their report (Reference 5.3) regarding the degradation mechanism. That a foreign object was not postulated as a possible damage mechanism was apparantly influenced by the fact that information available to the analysts indicated that the mechanical damage on the tube had been oriented toward the interior of the bundle, which was not likely to incur impact damage as a result of foreign objects. The licensee now believes that the initial orientation of the tube prior to removal could have been mis-established during the tube removal process.

Most of the tubes plugged 1 or 2 rows inboard of the periphery were in the Number 4 wedge area, and these tubes generally exhibited OD type eddy current indications at the time they were plugged, instead of the ID indications generally observed at the periphery. The postulated initial degradation in 1976 for these tubes is mechanical wear caused by rubbing from adjacent tubes as indicated by the results of metallurgical examinations of some of these tubes (Section 5.4.4).

Some peripheral tubes on the outer periphery near the number 4 wedge area and at the number 2 wedge area did exhibit OD indications at the time they were plugged (See Table 5.4.1). The OD indications for the peripheral tubes near the Number 4 wedge area are attributable to wear caused by a broken piece of tubing which was found to be wedged between the tubes (see discussion of Battelle Columbus tube examination in Section 5.4.4). No tubes were removed from the Number 2 wedge area and the cause of the OD indications at this location has not been established. A small tube fragment was found nearby. Video inspection of these tubes revealed no visible damage to these tubes. One tube, R32 C16, located one row in from the periphery at the Number 2 wedge area also was plugged as a result of an OD indication. This indication was localized in terms of its length rather than occurring over a several inch length such as is the case in the number 4 wedge area. Metallurgical examinations performed on tubes in the Number 4 wedge area indicate that tubes interior to the bundle incurred wear damage which is postulated to be the result of rubbing action from adjacent tubes which were observed to have become severed. Mechanical

Table 5.4.1 History of Tube Plugging in B-Steam generator periphery

Date/Event	Tube	Location	Licensee's Reason for Plugging (see notes)
1/76/Outage	R39C69	4W(Wedge Area)	(b)(c)(i)
	R40C68	4W	(a)(i)
5/76/Leak	R8C92	6W	(f)
	R9C91	6W	(a)(d)(e)
	R10C91	6W	(d)(e)
	R11C91	6W	(c)
	R12C91	6W	Leaker (a)(c)
	R13C90	6W	(a)(d)(e)
	R14C90	6W	(a)(d)(e)
	R15C90	6W	(a)(d)(e)
	R15C89	6W	(a)(d)(e)
	R16C89	6W	(a)(e)
	R17C89	6W	(a)(e)
	R30C15	2W	(b-47%)(e)
	R31C15	2W	(b-43%)(e)
	R33C15	2W	(a)(c)
7/77/Leak	R45C54	4W	Leaker (a)(c)
	R44C55	4W	(a)(c)
	R44C56	4W	(a)(c)
	R44C57	4W	(a)(c)
	R44C58	4W	(a)(c)
	R12C2	4W	(g)
1/78/Leak	R44C54	4W	Leaker (a)(c)
	R45C53	4W	(a-50%) (c)
4/78/Outage	R45C50	4W	(c)(g)
	R45C51	4W	(c)(g)
	R45C52	4W	(a) Tube pulled
	R44C52	4W	(c)(g)
	R44C53	4W	(c)(g)
	R43C58	4W	(a)(c)(d)
	R43C59	4W	(a)(c)(d)
	R43C60	4W	(a)(c)(d)
	R43C61	4W	(a)(c)(d)
	R41C66	4W	(c)(c)
	R40C67	4W	(a)(c)(d)
	R39C68	4W	(c)(g)
	R39C70	4W	(a)(c)
	R38C71	4W	(a)(c)
	R38C72	4W	(a)(c)

Table 5.4.1 History of Tube Plugging in
B-Steam generator periphery (Cont.)

2/79/Outage	R28C12	2W	(b-40%) No. 1 TSP
	R43C57	4W	(b-40%) (c)
	R43C56	4W	(b-68%) (c)
	R35C75	4W	(b-50%) No. 2 TSP
12/79/Leakage	R43C54	4W	Leaker (a)(c)
	R43C57	4W	(a)(e)
4/80/Outage	R45C48	4W	(h),(b), 46%
	R45C49	4W	(h)(b), 23%
	R32C16	2W	(b)(d)
	31 tubes	Sludge, crevice	
4/81/Outage	R43C53	4W	(b), 75 to 80%
2/82/Leakage	R42C55	4W	Tube rupture

Notes:
(a) Inner surface metal loss
(b) Outer surface metal loss
(c) Indication above tubesheet
(d) Dent at first tube support plant
(e) Indicatin 2 to 4 in. above tubesheet
(f) Precautionary plug
(g) Uninterpretable signal on outer or inner surface
(h) 24 in. above tubesheet
(i) Within tubesheet

analyses and tests described in Sections 5.4.5 and 5.4.6 indicate that tube severance is a precondition for the tube being free to rub against an adjacent tube. It is unlikely that any of the outer tubes in the Number 2 wedge area have become severed and rubbed against tube R32 C16 since the large lateral loadings required to cause such a severance would be expected to produce visible damage on the outer surface ot the tube.

By virtue of the peripheral location of the OD indications and the fact that it is located 2 inches above the tube sheet, there is no concentration medium for corrodants such as sludge to buildup or a crevice at this location. Normal thermal and hydraulic loadings in the absence of lateral loads caused by foreign objects or an adjacent severed tube would not be expected to cause OD metal loss (See Section 5.4.5). Thus, a foreign object which could fit and possibly wedge between tubes would appear to be the most likely explanation for the OD metal loss indication for tube R32 C16 , but this has not been confirmed.

5.4.4 METALLURGICAL EXAMINATION OF GINNA GENERATOR TUBES

In order to establish the cause of the Ginna Steam Generator tube rupture the licensee removed a number of tubes from the number 4 and number 6 wedge areas of the steam generator for metallurgical examinations. These examinations were performed for the licensee by Westinghouse and Battelle Columbus Laboratories and for the Nuclear Regulatory Commission by Brookhaven National Laboratory (BNL).

All tubes categorized as "structurally degraded" (tubes that are collapsed, severed, or have visible through wall defects) and several tubes categorized as having outer surface indications, such as a minor ding or wear mark, were removed for metallurgical examination. Tube cutting was accomplished from the secondary side of the steam generator through access holes opened in the steam generator shell opposite the number 4 and number 6 wedge areas, respectively. In the number 4 wedge area, a number of tubes were found that had been severed a few inches above the top of the tube sheet, and two were found to be missing, that is, had both severed just above the tube sheet and just below the first tube support plate. The two tubes immediately outboard of

the ruptured tube (R43 C55, R44 C55) were observed to be severed just above the tube sheet. Initial examinations were performed on those tubes that had severed and on the ruptured (fishmouth) tube by Westinghouse for the licensee. One of the missing tubes (R45 C54) was found to be severed at both ends and wedged between the wrapper and the outer row of tubes. This tube was retrieved and sent by the licensee to Battelle Columbus for examination. Subsequently, the remaining degraded tubes in the number 4 wedge area and the structurally degraded tubes in the number 6 wedge area were removed for examination. BNL received portions of the original tubes examined by Westinghouse (including the fishmouth), the missing tube (R44 C56) which was retrieved, and selected other tubes from both the number 4 and the number 6 wedge areas.

The following summarizes the observations made in the metallurgical examinations at Westinghouse, at Battelle Columbus, and at Brookhaven National Laboratory.

5.4.4.1 Westinghouse Results

Extensive investigations have been performed to date on six tube segments which were removed from the number 4 wedge area including R42 C55, (the ruptured tube), R44 C54, R43 C54, R43 C55, R44 C55, and R43 C56. Examination techniques included non-destructive examinations, dimensioning, macrophotography, optical metallography, scanning electron microscopy (SEM), fractography, and microhardness determinations. In general, all degradation processes were found to be mechanical in nature with no evidence of corrosion.

Tube R42 C55 which suffered the axial burst rupture was found to exhibit two long axial wear scars, one of which reduced the original 0.050 inch wall thickness to approximately 0.008 inches for approximately 4 inches in length. The total length of the wear scar was approximately 6 inches. The resultant burst at this location was found to be completely ductile in nature.

BEST DOCUMENT AVAILABLE

All five other tubes examined showed wear areas similar to those seen on the burst tube. These axial areas of wear are several inches in length, and exhibited circumferential grinding marks or striations. Most wear surfaces were shown through metallography and with microhardness measurements to have minor degrees of cold work (< 1 mil). Other wear areas, such as the burst wear surface, do not show evidence of cold work.

Severed, previously plugged tubes were found to be worn through in several areas, and the fracture surfaces for two of these exhibited evidence of fatigue. This breakage process is consistent with a wear process having reduced the remaining axial ligaments to the point where these ligaments did fatigue and tear. Some of the other areas of breakage were not discernable, due to the fact that the fracture faces were obliterated by the damage process to the extent that details were lost to the SEM investigation. However, the evidence indicates that fatigue or tensile overload of minimum ligaments operated to complete the damage process.

Tube R44 C55, an outer tube which was collapsed on the lower two inches of the specimen, was found to exhibit extensive cold work on the collapsed surface.

Attempts to align the wear surfaces on the burst tube with wear surfaces on adjacent, previously plugged tubes demonstrated that the adjacent tubes were relatively free to move since they had been severed near the top of the tube sheet. On the burst tube, for example, the wear scar associated with the burst faced the backside of the neighboring tube R43 C55 (which was severd), and faced the wrapper. There was, however, a second wear scar on R42 C55 which was displaced circumferentially by an amount which confirms that severed tube R43 C55, which caused the wear, was mobile. Examination of other worn, previously plugged tubes, also revealed wear that penetrated through the tubing wall.

2) Battelle Examinations

The preliminary results of the Battelle failure analyses were presented to representatives of the NRC staff and their consultants at a meeting at Westinghouse on April 27, 1982. Battelle examined a tube (R45 C54), which had been severed at both ends, found wedged between the wrapper and the outer row of tubes. Extensive cold work of the outer surface was found in a collapsed area of the tube. This tube contained numerous wear scars approximately 2-3/8" apart. The scars were at an angle and spacing that is entirely consistent with these wear scars having been produced by vibration against tubes. All six scars are of the same size. Battelle also examined one intact tube (R45 C47), which showed a slight bulge near the center of a 50% throughwall wear scar. A minor degree of cold work was associated with the wear area on the tube that had been completely severed, and evidence of fatigue was observed where this completely severed tube had broken near the first tube support plate. A slight increase in hardness of the tube material was observed in the wear scar areas.

3) Brookhaven National Laboratory Examinations

Independent examinations performed for the NRC staff at BNL confirmed the findings of the licensee and his consultants. Detailed findings of the BNL investigation are provided in Appendix A to this Safety Evaluation Report. Wear was found on the surface of all of the tubes. Significant amounts of cold work however, appeared to be confined to the tubes that gave evidence of having been impacted by a foreign object as opposed to tubes from the inner rows, which appeared to have been worn from an adjacent tube severed at the lower end. On the lower half of the fishmouth in the ruptured tube there was no evidence of a sharp scar. This suggested that the wear that caused this fishmouth was evenly distributed over a long axial distance of the tube and was caused by rubbing of a nearly parallel surface, and was not touched by the broken off area of the adjacent rubbing tube. BNL also found no evidence of primary side stress corrosion cracking on any of the tubes received but did observe

shallow (up to one 1.0 mil) intergranular attack on the primary side of one of the tubes examined. This amount of intergranular attack is consistent with the depth of attack anticipated from a severe pickling operation, and probably was present on the tubes at the time of manufacture. The outer row tube (R44 C59) tube examined at BNL that was classifed as waving a video O.D. indication, was found to contain an impact mark with identifiable iron particles indicating that this defect had been caused by impact from a foreign object, probably made of carbon steel.

The staff has concluded the following, based upon the results of the metallurgical examinations.

1. All damaged observed to peripheral tubes is of a mechanical nature. Specific mechanisms involved include impact, collapse, fatigue, fretting type wear/abrasion, and ductile overload and tearing.

2. Tubes located inside the outer row of tubes exhibited a fretting type wear with no evidence of significant cold work while peripheral tubes exhibited significant cold work. This is consistant with the hypothesis that damage occurred on the outer tubes as a result of impact by foreign object(s). This theory is substantiated by the discovery of iron particles on the outer surface of an outer periperal tube.

3. Metallurgical findings from all three laboratories are consistant with the postulated failure mechanism (Section 5.4.2), whereby foreign objects initiated a sequence of events which led to the plugging of a number of tubes in the peripheral region of B-steam generator and ultimately to the tube rupture on January 25, 1982.

5.4.5 ANALYTICAL ASSESSMENT OF FAILURE

5.4.5.1 Scope

This section describes the results of the analyses performed by the licensee to establish the nature and magnitude of loads acting on the steam generator tubes

and discusses the staff assessment of the role that these loads played in the postulated failure mechanism described in Section 5.4.2. The analyses included thermal and mechanical loads due to normal operating transients, lateral loads due to foreign object impact, and hydraulic loads including consideration of vortex shedding, cross flow turbulence and fluid elastic excitation. Axial loads due to pressure and thermal growth mismatch and loads resulting from impact of a foreign object on the steam generator tube have been evaluated. The potential for tube collapse due to possible thermal, mechanical and hydraulic loads identified for the Ginna steam generator has been examined. The effects of tube ovality on the tube collapse mechanism has been evaluated. The stability characteristics and magnitude of the flow induced vibrational displacements and loads for hot leg tubes between the tube sheet and the first support plate have been determined. A tear in a steam generator tube might result in a protrusion which could be acted upon by fluid induced alternating lift and drag loads to further increase the extent of the wear. An estimate has been made of the magnitude of these loads so as to establish the role that fluid effects might have played in the shredding of the tubes. Analytical calculations have been performed to assess the fatigue characteristics of the plugged tubes, with and without notches and tubes with locally collapsed sections.

The period of time for sufficient wear to occur so that bursting of a tube would result has been calculated. The rubbing of a neighboring tube by a severed tube due to flow induced motion has been evaluated. The minimum wall thickness to preclude bursting of an active tube has been determined and correlated with field data.

5.4.5.2 Thermal-Hydraulic Evaluation

The plugging or removal of tubes from the periphery of the hot-leg tube bundle resulted in a redistribution of the flow. The flow velocities resulting from this flow redistribution were evaluated to determine if flow induced loads on the tubes around the plugged tubes and the tube removal region were significantly affected.

The CHARM computer program (Reference 5.4) was used to perform a thermal-hydraulic analysis in the region of the tube bundle between the tube sheet and the first support plate. CHARM is a Westinghouse Proprietary two-dimensional analysis code used to compute the fluid flow conditions in a two dimensional domain. The basic variables computed are the pressure, velocity, density and enthalpy. The CHARM calculations included the following cases for the plugged tube region: (a) Ginna nominal base case at 100 percent power, and (b) a perturbed case simulating a plugged tube region five tubes pitches deep (approximately 80 tubes).

A separate three dimensional hydraulic analysis was performed of the tube sheet-to-first support plate region with the Westinghouse WECAN hydraulic conductance element (Reference 5.5). The purpose of this analysis was to determine the effect of tube plugging on the three dimensional aspects of the flow distribution. This analysis used a pressure-force boundary condition.

The major effect of tube plugging was the appearance of a reduced fluid velocity field and low quality region between the wrapper opening and the region where the tubes are plugged. This tended to increase fluid cross flow velocities in the plugged tube region near the wrapper entrance. The highest between-tube cross flow velocity increased from 9.01 ft/sec. in the no-plugged tube case, to 9.11 ft/sec. in the plugged tube case or slightly more than one percent, which is not considered a significant increase. Thus, the plugging of tubes in the hot-leg periphery does not produce unacceptable consequences from a thermal hydraulic standpoint.

5.4.5.3 Structural Evaluation of Foreign Object Induced Loads

The licensee has investigated analytically the failure mechanism of a plugged tube under the combined loadings of external hydraulic pressure, axial loads and impacting loads from a foreign object similar to the largest object removed from the Ginna steam generators. Axial loads can result from external pressure, plant transients such as loading/unloading, hot standby with 70°F feedwater and plugged tube-to-active tube thermal interaction. At the non-load steady state condition, all components are at a uniform temperature and, hence,

axial tube loads following the hot standby and plant unloading transients approach zero as the temperatures approach steady state conditions. Therefore, these transient axial loads have only been considered in the fatigue analysis; whereas axial loads acting over a longer duration have been considered in the analysis of the collapse mechanism and flow induced vibration analysis. Tensile axial loads occurring during steady-state conditions would be important from the view point of increased susceptability to collapse.

The mathematical model used to analyze the dynamic effects of a lateral impact loading from a foreign object on a steam generator tube consists of a steam generator tube simulated as a spring mass system. In one model, the deformation of the tube was assumed to follow the mode shape of the first fixed-fixed beam mode between the tube sheet and the first support plate. As such, the applied loading was related to the mass-per-unit length of the tubing between the tube sheet and first support plate. In a second model, the spring constant and mass were based on the static deflection profile of a fixed-fixed beam with a point load applied at a location four inches above the tubesheet. The second model is more representative of lateral impact loads being applied to a tube such as occurred at Ginna. The foreign object and tube equations of motion have been numerically integrated in time. The following three cases have been analysed.

Case 1 considered the translation of the foreign object from a position near the shell to the steam generator tube as a result of fluid forces associated with a nominal fluid velocity of 2.3 ft/sec. Cases 2 and 3 simulated the type of behavior which might be expected when the steady fluid velocities were lower than the nominal and alternating velocities because of a disturbance produced by an object like a support block.

The results of the analyses indicate that foreign object impact loads in excess of 100 lbs. are possible even for a beam type deformation of the impacted tube. Shell type deformations were not analyzed but are likely to lead to higher loads.

5.4.5.4 Structural Evaluation of the Collapse Mechanism

An analysis was performed to determine the potential for tube collapse due to possible thermal, mechanical and hydraulic loads identified for the Ginna steam generator in conjunction with the postulated failure mechanism discussed in Section 5.4.2. In this analysis, the tube was assumed plugged and subject to the secondary side external pressure. In addition, an axial load which arose from restraint at the first tube support plate was assumed to act on the tube. A radial load associated with a foreign object impacting the tube near its tube-sheet end and causing local deformation of the tube wall was then superimposed on the pressure and axial restraint loading. Results of the analysis indicated that random and repeated application of such a load can result in degradation of a local area of the tube surface and in progressive tube ovality such that under the combined effects of the axial restraint, external pressure and impact, the tube would collapse when the ovality reaches a critical value.

5.4.5.5 Flow-induced Vibration and Stability Characteristics

The licensee has made a determination of the stability charateristics and magnitudes of the flow induced vibrational displacements and/or loads for hot-leg tubes between the tube sheet and the first support plate. This information is pertinent to assess the degree of fatigue usage as a result of fluid-solid interactions. Both gross and local hydraulic effects have been considered. Gross hydraulic effects are those which act on a tube and are of interest relative to the overall response characteristics of the tube. The loading mechanisms are fluid elastic excitation, vortex shedding and turbulence. Effects of tube plugging, structural degradation and axial loading have been considered in the analysis. In the local hydraulic load analysis, the magnitude and frequency of lift, drag, and torsional loads acting on a tubing protrusion have been calculated.

A tube is considered to be stable when the fluid elastic stability ratio is less than unity. The stability ratio (Ue/Uc) is defined as the ratio of the effective velocity (Ue) to the critical velocity (Uc). The effective velocity is a function of the distribution of secondary fluid-flow velocity along the

tube axis, fluid density, tube mass, and the vibrational mode shape. The critical velocity (Uc) is the threshold velocity above which the tube amplitude increases as the secondary fluid velocity is increased and the induced energy from the fluid exceeds the damping energy dissipated by the tube. Computed fluid-elastic stability ratios for several tube configurations and for the fixed-fixed and fixed-pinned boundary conditions, have been calculated by the licensee.

Cross-flow turbulence was evaluated, because it causes narrow band random vibration of tubes at about the natural frequency of tubes in the fluid. The vibration amplitudes vary randomly in time and direction. Turbulence is thought to be the main cause of tube vibration in steam generators when the possibility of fluid-elastic excitation has been eliminated. Of the three mechanisms identified with flow induced vibration, amplitudes generated by turbulence are smaller in magnitude than those generated by fluid-elastic excitation or vortex shedding. In closely spaced tube arrays, it is considered that the predominant mechanisms are turbulence and fluid-elastic excitation.

Since the cylindrical and the flat cross-section are limiting configurations, analysis was extended to include an assumed 1000 lb compressive load being applied to both configurations. A compressive load tends to decrease the natural frequency and reduce the stability margin. This compressive load could occur as a result of secondary pressure, tube-to-shell interaction or a thermal growth mismatch due to restraint at the first support plate.

The major results of the flow induced vibration analysis are summarized below.

1. Cross-flow velocities in the range of 9 ft/sec can cause peak root-mean-square amplitude vibrations of 0.6 mils for a fixed-fixed cylindrical cross section tube and approximately 1 mil for a fixed-pinned cylindrical cross section tube. The application of a 1000-lb compressive force had a negligible effect. Maximum amplitudes of vibrations would be roughly a factor of seven higher than the peak root-mean-square vibrations.

2. Cross-flow velocities in the range of 9 ft/sec can cause peak root-mean-square amplitude vibrations of 1 mil for a fixed-fixed flat cross section tube and approximately 3 mils for a fixed-pinned flat cross section tube. The application of a 1000-lb compressive force had a small effect. Maximum amplitude vibrations would be roughly a factor of seven higher than the peak root-mean-square vibrations.

3. Fluid-elastic instability of the flat cross section tube for a fixed-fixed boundary condition will occur for fluid velocities in the range of 11.5-16 ft/sec. Since maximum cross-flow velocity is of the order of 9 ft/sec, fluid-elastic instability is not predicted analytically.

4. Fluid-elastic instability of the flat cross section tube for a fixed-pinned boundary condition will occur for fluid velocities in the range of 10-14 ft/sec. Since the maximum flow velocity is of the order of 9 ft/sec, fluid-elastic instability is not predicted analytically.

Thus, plugged tubes with locally collapsed sections will not produce unacceptable flow-induced vibrations.

5.4.5.6 Fatigue Evaluation of Plugged Tubes

Analytical calculations were performed to assess the margin to fatigue failure due to the worst case combination of thermal, mechanical, and hydraulic loadings. This assessment was done for both nominal and degraded plugged tubes, with and without continual lateral impact loading from a foreign object.

For the case of a nominally plugged tube, the stress categories used in calculating the stresses, included pressure stress, bending stress due to in-plane thermal growth mismatch between the tube sheet and support plate, bending stress in the tube due to rotation of tube sheet as a result of primary-to-secondary pressure differential, bending stress in the tube due to as-built offset, axial stress in the tube due to thermal growth mismatch between tube and stub barrel, axial stress in the tube due to thermal growth mismatch between plugged tube and active tubes, and hoop bending stress due to two percent ovality.

In the case of a nominally plugged tube with a notch, a stress concentration factor of 4.0 was applied to the axial stresses for peak stress effects in addition to the stress categories mentioned above.

A third case analysis was performed for a plugged tube with a locally collapsed section and notch or stress riser type degradation, with and without continuous impact by a foreign object. The tube was assumed to be locally collapsed over a 2.0-inch length beginning at 4.0 inches above the tube sheet. An analysis was performed to obtain the frequency and the root-mean-square stresses due to cross-flow turbulence. A 1000 lb axial load on the tube was considered in this analysis to simulate the effect of thermal growth mismatch loads due to axial restraint at the first tube support plate.

The uncollapsed portion of the tube was assumed to have a nominal two percent ovality. Hoop stresses on oval tubes under the combined effects of external pressure and various magnitudes of lateral loads were obtained from the detailed finite element analysis.

For a fixed-pinned condition, the maximum peak stress, due to cross-flow turbulence with a fluid velocity of 10.0 ft/sec and including a stress concentration factor of 4.0 for a notch, was equal to ± 11.24 ksi, which is less than the material endurance limit of approximately 13 ksi, at 10^{11} cycles.

Using the high cycle fatigue curves the allowable cycles for the worst case thermal-hydraulic cyclic loading have been determined.

Based on results of the fatigue analysis discussed above, both nominal and degraded plugged tubes without a lateral impact were found acceptable with adequate margin to fatigue faliure even under the worst case thermal-mechanical and hydraulic loadings over the design life of the plant. A plugged tube under axial compression, with a locally collapsed section and a notch or stress riser, subjected to a continual lateral impacting load is predicted to fail in

fatigue. The calculated failure time for this case varies from about a day to a few weeks depending on the magnitude of the impact loading.

5.4.5.7 Wear Damage Evaluation of Tubes

An assessment of the wear damage in Inconel tubes due to rubbing against other tubes, has been provided by the licensee. The calculations consider potential ranges of wear due to sliding contact of Inconel tubing in both water and air. It has been shown that a uniformly thinned 7/8 inch OD tube will burst when the wall is reduced to approximately 6.6 mils under normal Ginna operating conditions, assuming an ultimate strength of 89.7 ksi. Wear volume is determined by an empirical wear formula according to Archard's theory on wear.

For purposes of establishing a contact force for one tube rubbing on another, it was assumed that a severed tube is cantilevered from the tube support plate and is 50 inches long. Under fluid drag forces, the severed tube was assumed to lean against a neighboring tube that is supported both at the tube sheet and at the tube support plate.

When the severed tube was assumed to lean against a neighboring tube, it was also assumed that the neighboring tube will vibrate at its first natural frequency while the severed tube maintains contact with it. Based on the observed wear widths of 0 to 100 mils (circumferentially) on the tubes removed from Ginna, the mean amplitude of motion was taken as 50 mils.

The lower and upper bounds of the time periods to rub the tube thickness down to the minimum before burst was estimated to be 59 days and 1.27 years, respectively. The time periods calculated above reasonably envelope the observed wear range. For example, burst tube (R42 C55) went from less than 40% to 84% wall thinning between May 1981 and Janaury 25, 1982.

The wear patterns seen in the Ginna B steam generator suggest the rubbing of the O.D. of a neighboring tube by a severed tube. In particular, the severed tube would lay against the next tube and then would fret transversely against

it as a result of fluid-induced motion. In so doing, the severed tube would wear down the walls of the adjacent tube(s).

It is shown that mechanical, thermal and hydraulic loads are insufficient for tubes restrained at both ends to cause tube deflection sufficient for the tubes to interact, as evidenced by the lack of tube wear in regions mid-way between the tube sheet and first support plate. That is, wear by unsevered tube(s) does not represent the mechanism seen at Ginna.

5.4.6 Model and Laboratory Testing

In addition to the analytical program discussed in Section 5.4.5, the licensee conducted model and laboratory tests at Westinghouse to investigate the major elements associated with the postulated failure mechanism and verify some of the analytical results. The chief objectives of the test program were to determine the magnitude of foreign object impact loads on tubes and the extent of the foreign object mobility in the downcomer region. The test program also provided information on the stability characteristics of degraded tubes near the tube bundle entrance region and the extent of the tube-to-tube interaction once a tube becomes severed near the top of the tube sheet.

The tube bundle at the flow inlet region of the Ginna steam generator was represented by an array of forty-eight (48) tubes (.875 inch O.D.) extending from the tube sheet to the first tube support plate.

The tests were run at ambient pressure and temperature using the cold flow loop at Westinghouse's Tampa facility. Water flow to the test model was controlled by a flow measuring venturi. The maximum downcomer velocity was 14 ft/sec during flow testing.

Biaxial piezoelectric accelerometers were placed inside selected tubes to sense tube motions resulting from impact forces and hydraulic forces.

A foreign object, with similar dimensions to the largest object removed from the Ginna B-Steam Generator, was positioned in the downcomer annulus of the

test model. The orientation and position of the object within the wrapper annulus region was varied to determine its relative stability and susceptability to flow induced vibration. At each position, the object motion was observed through windows in the side of the test vessel and accelerometer and force transducer time histories were obtained.

Object motion was random in nature and motion occurred for virtually all orientations and positions. The object demonstrated the ability to assume various positions within the downcomer annulus as well as the ability to provide a relatively uniform cycle-loading on the tubes.

Foreign object impact forces were estimated by comparing accelerometer time histories recorded during flow testing with those obtained by striking the same tube with an instrumented impact hammer. Based on accelerometer calibration data, maximum foreign object impact forces measured during flow testing ranged between 120-180 lbs. Using the force transducer calibration data, impact forces ranged between 200-350 lbs are possible. The duration of the impact force was short, approximately one millisecond.

In order to investigate tube degradation from the foreign object during flow testing, an extended flow test was performed in which the object was allowed to remain in the test vessel for eight hours, while the downcomer flow was maintained at 14 ft/sec. Visual examination of the tubes indicated degradation at several locations, with the most significant degradation occurring on the R45 C54 tube.

Tubes with locally degraded, structurally degraded, and/or severed cross-sections could experience flow induced vibrations leading to fatigue failure. In order to investigate the flow induced vibration charactertistic of degraded tubes, the tube in R44 C58 was locally degraded by progessively machining away the cross-section at the location of maximum foreign object scars approximately four inches above the tube sheet.

The following observations may be made:

a. Tubes with undegraded and locally degraded cross-sections, including one tube containing a notch which cut out 60% of the tube circumference at that location, were stable with respect to flow induced vibration during all flow testing.

b. The tubing accelerometer response envelope increased in magnitude as the tubing cross-section was progressively degraded by machining it away. However the increase in the tube response became erratic when a foreign object was permitted to interact with the tube.

c. A tube severed near the tube sheet interacted intermittently with adjacent tubes. The severed tube tended to nestle between neighboring tubes and in such a position that tube motion was small, less than one-tenth of an inch.

5.5 STEAM GENERATOR REPAIR PROGRAM

5.5.1 Tube Removal

Based upon the diagnostic investigations and examinations described earlier, it is clear that all sections of tubes capable of causing damage to adjacent tubes and all foreign objects of significance must be removed in order to preclude a reoccurrence of the January 25, 1982 tube rupture event. To determine which tubes should be removed, the licensee categorized the plugged tubes in the periphery according to the following criteria:

a) structurally degraded - tubes that are collapsed, severed, or have visible through wall defects; the size of the defect is large enough to cause a significant reduction in section modulus.

b) video O.D. indication - tubes that were observed by video inspection to have minor dings, wear marks, or similar small defects on the outside; the

defects do not involve any significant loss of volume or reduction in section modulus.

c) eddy current signal - tubes that were observed by video inspection to have no defects on the outside; the tubes have no defect beyond that for which they were originally plugged.

d) preventatively plugged - 3 tubes surrounding R42 C55 preventatively plugged prior to performing the secondary video inspections; these tubes showed no defect either by eddy current or video inspection.

e) pulled tube - one tube (R45 C52) was pulled for metallurgical examination in 1978.

Table 5.5.1 lists all plugged tubes in the periphery by category. As seen in this Table, 24 tubes have been categorized as "structurally degraded", including the tube which ruptured. All defects categorized as "structurally degraded" were located in the number 4 and number 6 wedge areas between the tubesheet and first support plate on the hot-leg side of B-steam generator. The licensee has performed analyses and tests which are discussed in Section 5.5.8. of this report as justification for not including tubes with lesser amounts of degradation in the "structurally degraded" category.

To provide access for removing "structurally degraded" tube segments, two 3-inch diameter access holes were drilled into the steam generator shell at the number 4 and number 6 wedge areas respectively. Following repairs, the access holes were sealed with a cover plate and seal. The access holes were designed in accordance with the requirements of the ASME code.

A cutting procedure was used to remove tube segments between the tubesheet and approximately two inches below the first support plate. In one case, a tube had previously been severed immediately below the tubesheet. The geometric stability of remaining lengths of tubing following the removal operation is discussed in Section 5.5.7.4.

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

Table 5.5.1 Ginna Station B-Steam Generator Categoriation of Defects

CATEGORY	No. 6 WEDGE AREA	R40C70 AREA	No. 4 WEDGE AREA		No. 2 WEDGE AREA
1. Structurally Degraded	R8C92 R10C91 R11C91 R12C91 R14C90 R15C90		R42C55M R43C53 R43C54M R43C55M R43C56M R43C58	R43C59 R43C60 R43C61 R44C52 R44C53M	R44C55M R44C56 R44C57 R44C58 R45C53
2. Video OD Indication	R9C91 R13C90 R16C89 R17C89	R38C71 R38C72 R39C68 R39C69 R39C70		R45C51	
3. Eddy Current Signal	R15C89	R35C75 R40C67 R40C68 E41C66		R45C46 R45C47M R45C48 R45C49 R45C50	R12C2 R28C12 R30C15 R31C15 R32C15 R32C16 R33C15
4. Preventatively Plugged				R41C55 R42C54 R42C56	
Total	11	9		28	7

M Metallurgical Samples
R45C52 pulled April 1978.

BEST DOCUMENT AVAILABLE

A segment of one tube (R45 C47) extending from the tubesheet to the U-bend was removed from the U-bend region through an access hole cut in the wrapper. The cut end of the remaining portion of the tube in the U-bend was stabilized by means of a restraining device installed on the anti-vibration bar support.

5.5.2 Loose Parts Removal

The loose parts removal program was intended to remove all loose parts, regardless of size, from both steam generators. This task was accomplished either manually or with remote mechanical devices. Pieces too small to remove by these means were removed by vacuuming or water lancing.

5.5.3 Mechanical Plug Removal

The licensee elected to restore three tubes to service which had been mechanically plugged earlier in the outage as a preventative measure (See Section 5.3.1). Subsequent eddy current inspection confirmed that two of the tubes were free of indications. However, one tube contained an approximately 20% indication which was not present during the initial inspection performed earlier in the outage. This indication is believed to have occurred accidentally as a result of the cutting operations performed during the tube removal operation. This tube has subsequently been replugged.

5.5.4 Material Accountability for Steam Generator Modifications

The cause of the January 25, 1982 "B" Steam Generator tube rupture has been attributed to a portion of the downcomer flow resistance plate found on the tubesheet, the remainder of which was cut out and removed from the steam generator during modification work in April, 1975. A review has been performed of the Quality Control (QC) practices in effect during the 1975 downcomer resistance plate removal. The present Quality Control practices observed during the recent Spring, 1982 steam generator repair and mositure separator modifications have been compared to those in effect in 1975, to ensure that adequate corrective action has been taken to preclude a foreign object from inadvertently being left inside a steam generator.

5.5.4.1 Downcomer Resistance Plate Removal - 1975

Removal of the downcomer resistance plate from "B" Steam Generator was performed in accordance with procedure SM-75-24.3, Revision 0, April 21, 1975. The following controls were in effect to maintain accountability of tools and other loose objects during work inside the steam generator.

-- A Material Control Log was established to record and regulate all material and equipment entering and leaving the steam generator.

-- Tools and equipment were tied off with lanyards or other suitable means to minimize the number of objects dropped and the need for difficult retrievals.

-- A protective blanket material, Refresil, commonly used during welding operations, was placed below the resistance plate, between the wrapper and shell to catch dropped material.

-- A metal trough was held by a worker directly below each section of plate being cut to catch falling metal resulting from the flame cutting process.

-- Following completion of the plate removal modification, the work area was cleaned, QC performed a visual inspection of the work area and reviewed the Material Control Log.

5.5.4.2 Steam Generator Repairs and Moisture Separator Modifications - 1982

During March through May, 1982 a moisture carryover modification was performed in A and B steam generators, in accordance with procedures SM-3118.1 and 3118.2 respectively. The modification included removal of portions of the mid-deck plate and supports, and installation of steam-water deflectors and steam chimneys. Additionally, a portion of the wrapper was cut out to allow access to the tube bundle for tube removal and tube stabilization. Procedures EM 306 and 312 were followed for performing work inside the wrapper. As a result of the video scan discovery of foreign material on the secondary side tube sheet,

subsequent to the January, 1982 tube rupture event, the following provisions were established to assure greater positive control over material accountability during the steam generator 1982 repair and moisture carryover work than during the 1975 modification.

-- A contractor and licensee QC representative provided continuous coverage of the work.

-- A Material Control Log was established, similiar to the log generated in 1975.

-- Wood scaffolding was installed in pieces between the wrapper and shell in the downcomer region, and between the tube bundle outer periphery and wrapper. To ensure a good seal, a rubber strip was stapled over each joint where two pieces butted together, as well as on each outer edge adjacent to the shell or wrapper. The scaffolding, which provided a sound mechanical barrier to catch dropped material, was erected the full 360° between the wrapper and shell, and in the vicinity of the work site, between the tube bundle and wrapper.

-- QC hold points were included to require inspection of the scaffolds for proper seals prior to initiation of work.

-- QC hold points were included to require inspection of the scaffolds for proper seals and removal of all foreign material following completion of work.

-- Tools and equipment were tied off with lanyards, similar to the controls used in 1975.

-- In case an object was dropped form the work platform inside the steam generator, procedural actions were specified to assure its location was identified: allowing for subsequent retrieval. In several instances, work was stopped and an object sucessfully retrieved.

-- QC performed an accountability inspection of the pieces cut out of each steam generator. All pieces were layed out, compared to drawings of the moisture separator region, checked dimensionally and photographed.

-- Secondary-side video surveillance of the steam generator downcomer region and tube sheet was performed on both steam generators following completion of work.

Material accountability controls in use during the 1975 downcomer resistance plate removal modification were ineffective in detecting the presence of foreign material located in the secondary side of the steam generators. Deficiencies were evident by 1) the failure to perform a post maintenance accountability inspection of the removed resistance plates to ensure all pieces were accounted for, 2) failure to inspect and ensure that the blanket material was properly sealed prior to the initiation of work, 3) failure to provide a mechanical barrier, to catch dropped material, of a sufficient design to compensate for the poor blanket seal, and 4) failure to perform an adequate post maintenance inspection of the steam generator secondary side to assure identification and retrieval of all foreign material. The material accountability controls used during the 1982 steam generator modifications included major improvements over those used in 1975. Increased inspections and Quality Control included 1) an accountability for all the pieces removed from the steam generators as a result of the modifications, 2) an improved method of sealing off the downcomer region and sealing between the tube bundle and wrapper, and 3) an extensive video inspection of the secondary side prior to close out of the steam generators.

Although shortcomings were noted in the method of maintaining the 1982 material accountability log and documenting resolution of Quality Control Inspection findings, the combination of controls described in this section are considered by adequate by the staff to ensure accountability for loose objects inside the steam generators.

5.5.5 Post Repair Inspections and Tests

Following completion of the repairs in the B-steam generator, a series of inspections and tests were performed to assure that it is ready for return to service. Sections of tubes adjacent to areas involved in the repair operations have been eddy current examined to assure that no unacceptable defects are present. A final series of video inspections have been performed to assure that no loose parts or tubing fragments remain and to verify that no unacceptable O.D. defects were caused by the repairs. A secondary side hydrostatic test was performed to verify integrity of the access hole covers. A primary side hydrostatic test was performed to assure that no measurable primary to secondary leakage is present.

5.5.6 Loose Parts Monitoring Systems

The licensee in section 7.3 of the steam generator evaluation report stated that a loose part monitoring system (LPMS) will be installed on both steam generators at Ginna prior to returning the plant to power operation. The system is intended to provide indication of foreign objects in either the primary channel head or the secondary side of the tube sheet.

Even though no data are available to quantitatively demonstrate the effectiveness of LPMS on the detectin of loose parts in the secondary side, a LPMS conforming to the guidelines of Regulatory Guide 1.133 (Ref.) should be capable of indicating loose parts in both the primary and secondary sides of the steam generator. A loose part in the secondary side may lodge on the tube sheet or between tube support plates at various heights. The effectiveness of the accelerometer sensors to detect the loose metallic parts impact noises depends on the acoustic coupling of the sensors to the sound wave transmission paths. By placing sensors at strategic locations that are acoustically coupled to detect metallic impacts on the generator inside surface, tubes, tubesheet and tube support plates, the LPMS effectiveness can be enhanced.

For the Ginna LPMS, each steam generator will have four sensors place on the exterior surface of the steam generator. The locations of the sensors are

shown in Figure 5.8. One sensor is located on the inlet plenum region, two sensors at the tube sheet region, and one sensor above the tube sheet in the secondary side region. The system sensitivity is, as required by Regulatory Guide 1.133, capable of detecting a metallic loose part that weighs from 0.25 lb to 30 lb and impacts with a kinetic energy of 0.5 ft-lbf on the inside surface of the steam generator within 3 feet of a sensor. In addition, the system will be tested prior to being placed in service to determine background noise and system frequency signatures as well as the frequency specturm and on-line sensitivity for metallic impacts. It is the staff assessment that the Ginna LPMS, if conforming to the guidelines of Regulatory Guide 1.133 with proper calibration procedures and alert level settings, would be able to detect any foreign objects weighing over 0.25 lb in the steam generator. The licensee has agreed to supply the detailed LPMS program and system descriptions within six months for staff evaluation.

The primary purpose of a LPMS is for detection of loose metallic parts in general locations. More precise impact location or loose part characterization or tube fretting detection are more costly and difficult goals to achieve and are not required. Tube fretting may result from tube vibrational impact against the tube support plates or frequent impacts of loose or drifting objects on the tube. Continuous tube vibration during normal reactor operation may be registered by the LPMS as background noise during the LPMS calibration. Therefore, care must be taken during calibration to distinguish the tube vibration impact from other hydraulic and mechanical background noises. Intermittent vibrational impacts above background noise levels can be detected and the vibration that leads to tube fretting could be identified.

5.5.7 Intermediate Outage

An intermediate steam generator inspection outage is planned at no more than 120 effective full power days (EFPD) after return to power. During this outage primary side eddy current along with secondary side fiber optics, video and visual inspections will be performed. The purpose of these inspections is to assure that the corrective actions taken to preclude further periphery tube O.D. defects have been successful.

5.5.8 Technical Justification for Repair Program

The licensee has provided analysis in Section 6.0, 6.1 and 6.2 of Reference 5.1 to verify the acceptability and compliance to the ASME Code the acceptability and compliance to the ASME Code requirements of the Ginna B steam generator. The following analyses were performed in support of the repair program.

The thermal/hydraulic analyses were performed to determine the type of flow redistribution due to the removal of structurally degraded tube spans on the hot leg periphery and to examine the effect of the flow redistribution on the fluid induced vibration characteristics of the remaining tubes. Based on detailed analyses, it was shown that the maximum tube gap velocity was increased by approximately 12 percent. However, the modification was determined to be structurally acceptable since significant margin exists for both the fluid-elastic stability ratio and vibrational stresses due to cross-flow turbulence.

Structural analyses of the secondary shell were performed for the two 3-inch diameter access ports to verify acceptability of the shell in accordance with the Code, subject to the applicable loading requirements in the Equipement Specifications. Based on these analyses, the access ports were determined to be structurally acceptable. Analyses were performed to determine the structural acceptability of plugged tubes with visual surface irregularities such as small scars or stress risers. The evaluation considers both the fatigue margin under operating transients and collapse integrity of such a tube. Additionally, the geometric stability of tube(s) severed just below the first tube support plate was also examined. Plugged tubes with minor surface irregularities and tubes severed just below the first support plate were shown to be structurally acceptable.

5.5.8.1 Thermal-Hydraulic Evaluation

The removal of tubes from the periphery of the hot leg tube bundle between the tube sheet and the first support plate will lead to flow redistribution. The flow velocities resulting from this flow redistribution must be evaluated to

determine if flow induced loads on the tubes around the tube removed region are significantly affected.

The licensee has used the CHARM computer program (Ref. 5.4) to perform thermal-hydraulic analyses in the region of the tube bundle between the tube sheet and the first support plate. Three cases were considered: (a) nominal (same as previously discussed in Section 5.4.5.2), (b) one block of tubes removed from the periphery of the bundle, and (c) two blocks of tubes removed in the periphery of the bundle. Case (b) is considered to be most representative of the proposed tube removal ($\simeq$ 80 tubes); Case (c) may be considered a very conservative upper bound. The CHARM analysis was performed in the plane of symmetry perpendicular to the tube lane which divides the hot and cold legs into equal halves.

Because the CHARM analysis was two-dimensional (axial and radial), a separate three-dimensional hydraulic analysis was performed of the tube sheet-to-first support plate region with the WECAN hydraulic conductance element as discussed in Section 5.4.5.2. (Ref. 5.5). The purpose of this analysis was to determine the effect of tube removal on the three-dimensional aspects of the flow distribution. This analysis used a pressure-forced boundary condition.

The result of these analyses show that the removal will have the following effects. The major effect of tube removal is the appearance of a reduced fluid velocity field and a low quality region between the wrapper opening and the first support plate in the region where the tubes are removed. This behavior is similar to the plugged tube case in Section 5.4.5.2. This low velocity region tends to increase fluid crossflow velocities in the region near the wrapper entrance.

The highest between-tube crossflow velocity increases from 9.01 ft/sec in the nominal case to 10.12 ft/sec in the one-block-of-tubes-removed case and 10.95 ft/sec in the two-blocks-of-tubes-removed case. These are increases of 12.3 percent and 21.5 percent, respectively.

As a result of their review of these analyses, the staff finds that the flow induced loads on the tubes in the region where other tubes have been removed around the tube removed region are not significantly affected and that the removal of tubes from the periphery of the hot leg tube bundle between the tube sheet and the first support plate will result in an acceptable flow redistribution.

5.5.8.2 Structural Evaluation

Tubes with significant reduction in stiffness and frequency due to the loss of cross sectional moment of inertia resulting from collapse, large holes and/or severance of tube were removed from the steam generator. On the other hand, tubes with visual surface irregularities due to small ovality and distortion and no significant reduction in stiffness were not removed.

The licensee addressed the structural acceptability of the tube bundle following the repair effort. Specifically, the following two considerations are examined for a plugged tube with surface irregularities:

(a) Fatigue margin under operating transients, and

(b) Collapse integrity

Additionally, the geometric stability of a tube severed and/or cut just below the first tube support plate (TSP) was also verified.

For the fatigue evaluation the thermal mechanical loads are the same as in the case of a nominally plugged tube discussed in Section 5.4.5.6. The effect of small distortion/ovality would be to increase the hoop bending stress due to the external pressure loading. For example, the maximum hoop stress for a nominally plugged 0.050-inch wall tube under 1000 psi pressure increases from 15.0 ksi at two percent ovality to 25.0 ksi at six percent ovality. This increase in the hoop stress had a relatively insignificant impact on the usage factor. Assuming a 30-year remaining plant life for a six percent oval tube with a design maximum wall of 0.045-inch, a significant fatigue margin exists

based on the code calculations in Section 4.5.7 of reference 5.1 for a notched, plugged tube. Thus, from the view-point of fatigue due to operating plant transients, plugged tubes with surface irregularities are acceptable.

From the viewpoint of hydraulic loading, the effect of tube removal on the maximum tube gap velocity was considered in order to determine the acceptance of such tubing subject to the mechanisms of fluid elastic stability, turbulence and vortex shedding. Details of thermal-hydraulic analyses to determine the maximum gap velocities for the before and after tube removal cases have been provided. The one-block-of-tube-removed case corresponds closest to the post-repair steam generator tube bundle geometry. The expected maximum gap velocity is 10.12 ft/sec, or approximately 12 percent greater than the calculated velocity prior to the tube removal condition.

Based on the results of flow-induced vibration analyses the staff concludes that the calculated velocity change has a rather insignificant impact on the fluid-elastic stability, turbulence and vortex shedding responses of a tube with given cross section and under a given boundary condition. The results also indicate that response of a tube with small ovality and/or distortions are essentially the same as those of a nominally round tube. The vortex shedding and cross-flow turbulence amplitude of a fixed-fixed tube span with various degrees of localized distortion and subjected to a 10.0 ft/sec cross-flow velocity over the 14.0-inch wrapper opening have been provided. Again, the comparison indicates that with the exception of the case of significant tube distortion or collapse, the vibration amplitudes are relatively stable, that is, about the same as the nominal round tube.

5.5.8.3 Collapse Integrity

Inconel-600 tubing typical of PWR steam generators has been extensively tested to determine the effect of local degradation on the external collapse pressure strength of the tubing. Results of an NRC-sponsored test program (Ref. 5.6) have been discussed. The results of this test program indicate:

(a) Expected collapse strength of a nominal tube is approximately 5000 psi.

(b) Collapse strength is relatively unaffected by short (length less than or equal to the tube diameter) through-wall cracks.

(c) For tube collapse corresponding to the external pressure of 1020 psi (maximum expected secondary side pressure for the Ginna steam generators) required tube wall degradation is approximately 80 percent for uniform thinning, and greater than approximately 90 percent for localized thinning.

Thus, tubes with small surface scars and localized wear have significant margin to collapse. As far as the effect of local tube distortion/ovality is concerned, it is to be noted that (1) the collapse mode of tube failure results from plastic instability of the tube shell and thus, represents instantaneous failure mode, and (2) of all the design-based loading conditions for the Ginna steam generator tubing, the maximum secondary side pressure of 1020 psi occurs during normal operation at the hot standby conditions.* In other words, plant operation (at hot standby) in itself represents a proof collapse test. Therefore, tubes with local distortions have ovality below the threshold of plastic instability and, thus, will not collapse. In the absence of any external mechanism, these tubes are expected to remain stable during subsequent operation.

5.5.8.4 Structural Integrity of Row 45 Tubes Between Columns 46 and 51

Tubes in row 45 between columns 46 and 51 have not been catagorized as "structurally degraded" (see Table 5.1.1) and merit additional discussion. As described in Section 5.4.3 of this report, a broken piece of tubing (R45,C54) was found wedged between these tubes and the wrapper. The broken tube was

*Secondary side hydro test, although at a pressure somewhat higher than the hot standby pressure of 1020 psi is not critical due to the offsetting effect of higher yield strength of Inconel at the lower temperature of the secondary hydro.

removed from the steam generator and found to exhibit roughly 2 inch long wear scars at regular intervals where it had rubbed the tubes. One of these tubes, R45 C47, was also removed for laboratory study and found to contain a 1 13/16" long x 5/16" wide x approximately 0.025" deep wear scar. It is likely that other above mentioned row 45 tubes contain similar wear scars corresponding to the wedged location of the broken tubes as evidenced by the fact that several of these tubes (except R45 C50 and R45 C51) exhibited OD eddy current indications at the time they were plugged. Similar wear scars could have occurred on tubes R45 C50 and R45 C51 after they were plugged in April 1978. The postulated wear scars on these tubes were too high (>12" above the tubesheet) to have been observed visually by the vidio camera inspection.

Tube R45 C46 was found to contain a 41% eddy current indiction during the current outage. A single linear wear scar with this amount of penetration does not have any significant affect on the local section modulus or overall stiffness of the tube.

Tube R45 C47 has already been removed form the steam generator. Tube R45 C48 and R45 C49, which were plugged in April 1980 as a result of 46% and 23% O.D. indications respectively and tubes R45 C50 and R45 C51 which were plugged in 1978 before detectable wear penetration had taken place, have not been removed.

It is likely that additional wear penetration of these tubes has occurred since they were plugged, but how much is not known.

However, even assuming that these tubes have worn sufficiently to cause a local tube collapse, the structural analyses and model slow tests described earlier (Sections 5.4.5.6 and 5.4.6) have demonstrated that these tubes will not be subjected to a flow induced vibrational instability or a fatique failure in the absence of lateral impact forces or a mechanism for continued wear of these tubes. Thus, the staff concludes that the continued presence of these tubes in the steam generator will not result in damage to adjacent unplugged tubes which could potentially result in another tube rupture. It should be noted that eddy current inspections to date of the adjacent unplugged tubes have revealed no

indications of wear. However, to provide added assurance that the four plugged tubes under discussion will not reinitiate the sequence of events which led to the tube rupture, the licensee has committed to performing a visual inspection of the wear scars on these tubes during the next steam generator inspection outage which will take place within 120 days following restart.

5.5.8.5 Geometric Stability of Cut/Severed Tubes

The degraded tube sections between the tube sheet and the first tube support plate (TSP) were removed by cutting the tube spans near the top of the tube sheet and 2 to 4 inches below the first TSP. Additionally, a small number of tubes had their lower spans severed (due to fatigue) just below the first TSP. The licensee has provided analyses to demonstrate the geometric stability of the remaining partial tubes. The postulated worst cast loading would occur during a postulated feedline break condition. It has been shown that the broken end tube will remain confined within the first TSP.

Thermal growth mismatches due to tube-to-tubesheet and tube-to-shell interactions during various thermal transients can result in motion of the broken tube leg relative to the TSP.

For a total pull-out through a 0.75-inch thick TSP, a required thermal differential of $T = 1900°F$ is calculated assuming a constant expansion coefficient at 600°F. Compared to the required $\Delta T = 1900°F$ for the pull-out, the maximum expected ΔT's during normal operating and postulated LOCA transients are less than 100°F and 400°F, respectively. Thus, a significant margin to pull-out exists for thermal growth mismatches.

In addition to the above direct axial movements, the broken tube end can move axially also due to lateral tube deflection resulting from seismic and flow-induced vibrations. However, for the tube span between the first and second tube support plates, the vibration amplitudes are very small. Consequently, no significant axial movement of the broken tube will result.

5.6 SUMMARY OF FINDINGS

5.6.1 Failure Mechanism

Investigations of the mechanisms which led the tube rupture occurrence on January 25, 1982 have satisfactorily established foreign objects as the likely initiating cause of a sequence of events which led to the plugging of a number of tubes in the peripheral region of steam generator B and ultimately to the tube rupture on January 25, 1982.

It is postulated that initial impact damage to the outer row of tubes caused these tubes to exhibit ID type eddy current indications and leaks as early as 1976 leading to the plugging of these tubes. Continued impacting of these plugged tubes in conjunctin with normal thermal, pressure, and hydraulic loadings caused these tubes to collapse and become severed above the tubesheet. Once severed the tubes were free to vibrate over an approximately 50" span, pivoting at the first tube support plate. Wear on the inner row tubes occurred over lengths up to several inches. Until January 1982, these tubes were plugged as a result of OD type eddy current indications or leaks before wear had proceeded sufficiently through wall to cause a tube burst. After these tubes were plugged, wear degradation continued to the point such that they too became severed and were free to interact with additional neighboring tubes. Eventually, wear occurred homogeneously over a long enough length of an inner row tube that it burst.

Supporting evidence for the postulated failure mechanism includes the following:

1. The largest foreign object found was a piece of the flow-resistance plate most of which was removed during steam generator modifications performed in 1975. This piece apparently fell, unnoticed, on to the tubesheet outside the periphery of tube bundle during the cutting and removal operation. This occurrence predates the initial finding in 1976 of eddy current indications and leaks in the peripheral tubes. The history and pattern of plugging in the peripheral region is consistent, with the peripheral failure mechanisms.

2. Tube plugging in the peripheral region has tended to occur in discrete batches, generally at the wedge locations, and that the focus of plugging activity appears to have shifted with time from one wedge location to another. Flow testing has demonstrated that an object similar to the largest foreign object removed from Ginna would be mobile, tend to settle perferentially at the wedge area locations, and vibrate and impact the outer row tubes.

3. Outer tubes were the first to exhibit eddy current indications and leaks and thus were the first to be plugged. The eddy current indications were often interpreted as ID indications or bulges. Local wall distoritions, cold work, and free iron pickup as a result of impact from a foreign object are a possible explanation for this type of signal. Metallographic examination revealed no ID cracking or corrosion which would explain these indications.

4. All damage observed to peripheral tubes during visual and metallographic examinations is of a mechanical nature. Specific mechanisms involved include impact, collapse, fatigue, fretting type wear/abrasion, and ductile overload and tearing. Some tubes were observed to have completely severed near the top of the tubesheet, and in at least two instance also just below the first support plate; the upper break was clearly identifiable as a fatigue failure.

5. Inner tubes displayed a fretting type wear with no evidence of significant cold work, while outer periphery tubes displayed significant cold work. This is consistent with the hypothesis that damage occurred on the outer tubes as a result of impact by foreign object(s). This theory is substantiated by the discovery of iron particles on the outer surface of an outer periphery tube.

6. Analyses and Laboratory tests have demonstrated that lateral impact loads from an object the size of the largest piece found at Ginna in conjunction with normal thermal hydraulic and pressure loads can result in sufficient tube ovalization to cause collapse of a plugged tube even where

essentially no wall thinning has taken place. A collapsed surface examined metallurgically exhibited evidence of impacting and cold work.

7. Analyses indicate that continued impacting of a collapsed tube by a foreign object can lead to a complete severance of the tube by fatigue. Calculated failure time ranged from a few hours to a few weeks depending on the magnitude and frequency of the impact laods. Once a tube has been severed it can impact with neighboring tubes, wear sufficiently to degrade these tubes, such that they could also fail in fatigue or by burst if internally pressurized.

8. Tubes extending out to the periphery from the loation of the burst tube exhibited wear scars similar to those observed on the burst tube. The alignment and orientation of the wear scars relative to the location of tubes severed at the tubesheet indicate that the severed tubes were free to move to cause rubbing and thus a fretting type wear of adjacent tube surfaces. This has been substantiated as a plausible mechanism during model flow testing when a tube severed near the top of the tubesheet was observed to interact intermittently with adjacent tubes. Analytical calculations indicate that sufficient thinning of a tube wall due to wear by an adjacent severed Inconel tube can occur such that bursting of an active pressurized tube could result consistent with the actual Ginna data.

9. Oscillating lift, drag and torsional fluid loads are not large enough to cause tearing or tubing protusions. Consequently, tube shredding must be related to another process, such as wear.

10. Analytical calculations indicate that a nominal plugged tube with or without a notch or stress riser will not fail in fatigue even under worst case operating thermal and mechanical loads.

11. Structurally degraded tubes will not fail due to fluid induced vibrations alone. Fluid elastic instability would not be predicted analytically for a mechanicaly or structureally degraded tube. However, for a structurally

degraded tube, the calculated margin to instability is small. During model flow testing, tubes with degraded and structurally degraded cross section were stable with respect to flow induced vibration.

5.6.2 Eddy Current Testing

1. The eddy current inspection program was adequate in scope to define problem areas. A complete (100%) sampling of tubes in these problem or potential problem areas has been performed.

2. Eddy current test procedures employed at Ginna meet or exceed ASME Code requirements and are state f the art.

3. The eddy current procedures employed by Ginna are adequate for purpose of detecting gradual wear type flaws such as the kind which led to the tube rupture. Where eddy curent indications are found, and where long gradual wear type flaws may be the source of the indication (such as at the periphery), use of special calibration standards for wear type flaws may be necessary to assure a conservative interpretation of the signal. During this outage, no such indications were found except for three tubes which were plugged.

4. The rupture type exhibited an indication, several inches long, which was not recorded during the April 1981 inspection. This signal would have been interpretable as a 20% indication utilizing the ASME Code calibration standard. However, with use of the specially constructed wear standard, the signal is interpretable as slightly greater than a 40% indication which compares with the 40% plugging limit.

5. Eddy current data fro the current outage was reviewed by an NRC staff representative for three tubes immediately adjacent to the tube which ruptured. The results of this review corroborated the licensee's finding that these tubes were free of indications.

6. Regarding the scope of the eddy current inspections performed, the licensee has performed a 100% inspection sample in those areas where tube degradation is a likely possibility based on past experience including all of the hot leg and the outer two rows of the cold leg to the first support plate. A random sample of 4% of the tubes were inspected end to end with the finding of no indications outside the regions which received a 100% sample inspection. Based upon the above and the fact that the sample sizes met or exceed existing requirements, we find there is no basis to require additional inspections prior to restart.

5.6.3 Television Inspection

Tapes of the television video data have been reviewed by the staff. We find that the video pictures are of sufficient resolution and clarity to allow an assessment of the degree of damage to previously plugged tubes.

5.6.4 Post Repair Structural Integrity of Plugged Tubes

The staff has concuded that all previously plugged tubes which are sufficiently degraded to potentially cause damage to adjacent tubes have been removed from the steam generators. Removal of these tubes and all foreign objects of significance precludes a recurrence of the sequence of events which led to the tube rupture event on January 25, 1982. Small foreign objects or loose parts which may have escaped detection and removal would not be expected to be large enough to cause a recurrence of the mechanisms which led to the tube rupture.

The staff has concluded that plugged tubes which have not been removed from the steam generators retain adequate structural integrity to preclude any adverse affect on fluid elastic stability, vortex shedding and turbulence response.

We conclude that for these tubes an acceptable fatigue margin exists for subsequent operation. Removal of structurally degraded tubes has no adverse impact on the stability of the remaining tubes due to fluid interactions. Tubes

BEST DOCUMENT AVAILABLE

severed at the first TSP are geometrically stable and cannot pull out of the plate due to operating and faulted transients.

Linear wear scars are believed to exist for four previously plugged tubes at the outer periphery in row 45 of steam generator B which could not be viewed by the video camera.

However, even if it is assumed that the wear scars have resulted in a local collapse of the tubes, structural analyses and model flow tests have been shown that these tubes will not be subject to a flow induced instability or a fatigue failure.

The licensee has committed to performing a direct visual inspection of these wear sears (probably using fiber optics) during the next inspection outage to occur 120 days following restart from the current outage.

The licensee's plan to shutdown after 120 days operation for followup eddy current and video inspection will provide added assurance that the corrective actions taken to preclude further peripheral tube degradation have been successful.

The safety and integrity requirements of active tubes are satisfied by existing inspection and repair limit requirements for steam generator tubing.

5.7 References

5.1 Rochester Gas and Electric Company, "Steam Generator Evaluation", dated April 26, 1982.

5.2 NUREG-0886, "Steam Generator Tube Experience", February 1982

5.3 EPRI Report NP-1412, Project 1166-2, "May 1980.

BEST DOCUMENT AVAILABLE

5.4 A. C. Spencer, "Method of Characteristics for Solving Two-Dimensional Reactor Core Flows", proceeding fo the 1973 Conference on Mathematical Models and Computational Techniques for Analysis of Nuclear Systems", CONF-730414-P1(ANS), 1973, pp. III-3 to III-22.

5.5 WECAN: Westinghouse Electirc Corporation Analysis, User's Manual, Second Edition, March 1981.

5.6 NUREG/CR-0718, "Steam Generator Tube Integrity Program-Phase I Report", September 1979.

ENCLOSURE 1 TO NRC-01-0044

BEST DOCUMENT AVAILABLE

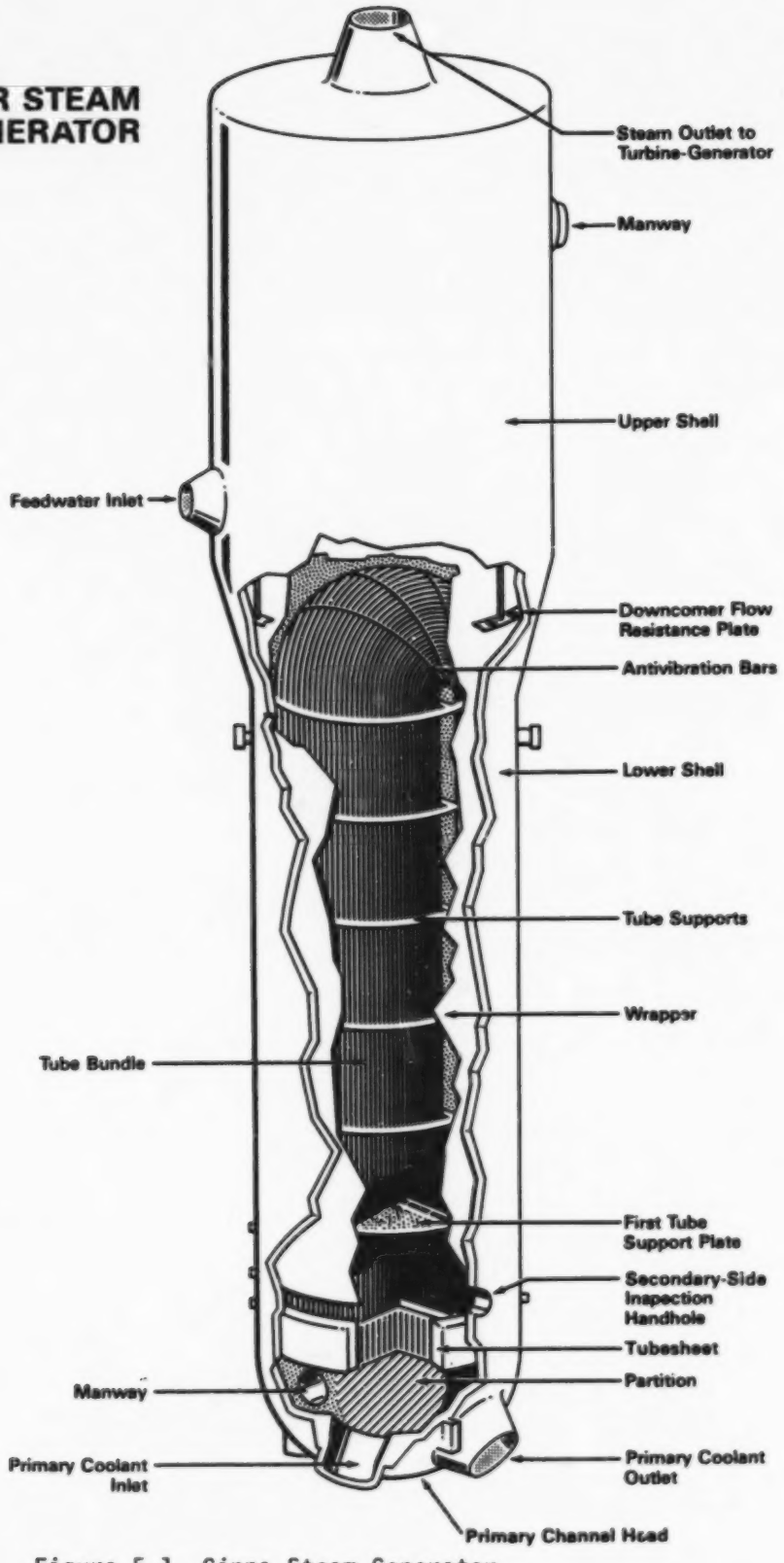


Figure 5.1 Ginna Steam Generator

BEST DOCUMENT AVAILABLE

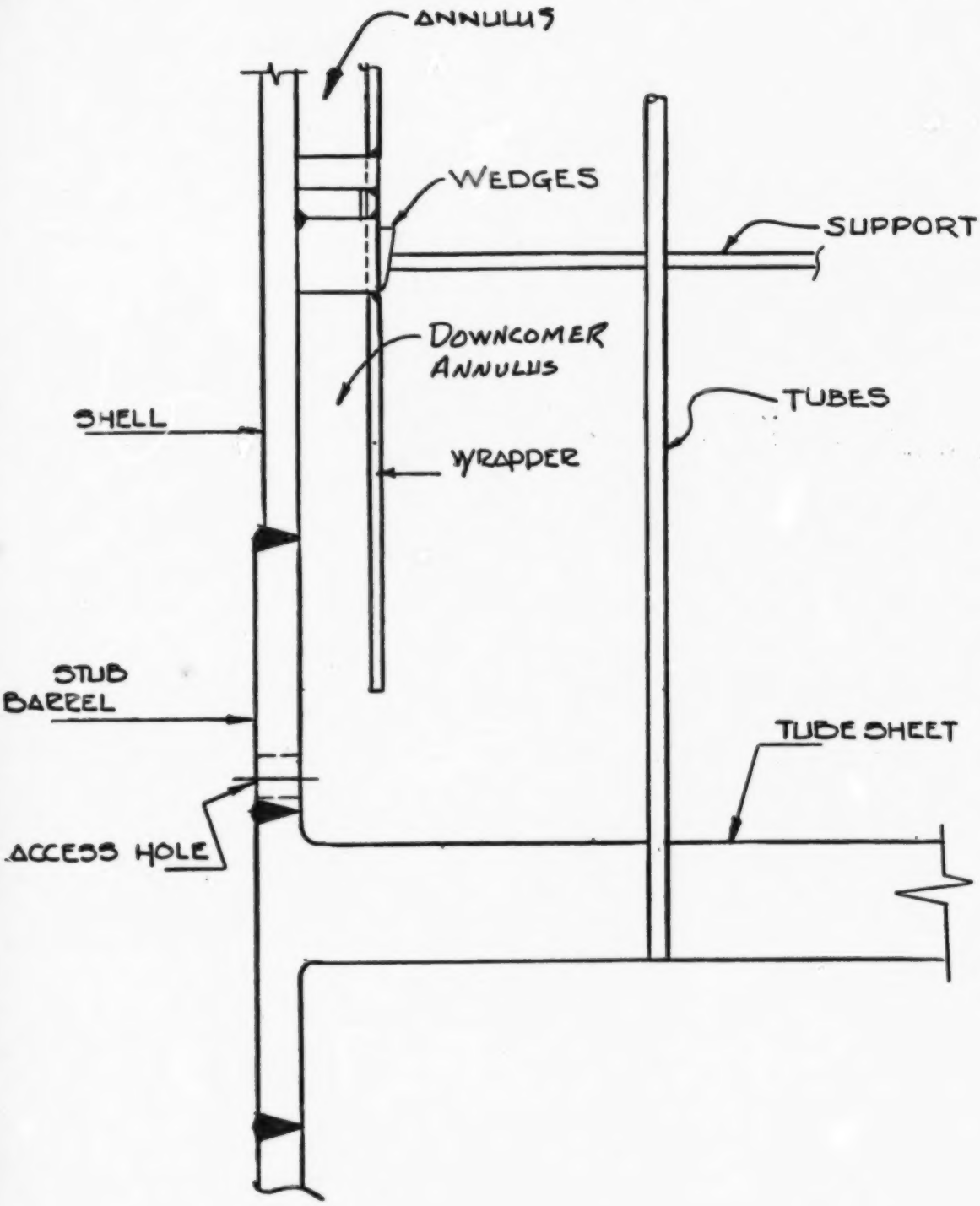


Figure 5.2 Schematic of "B" Steam Generator Tubesheet Area

BEST DOCUMENT AVAILABLE

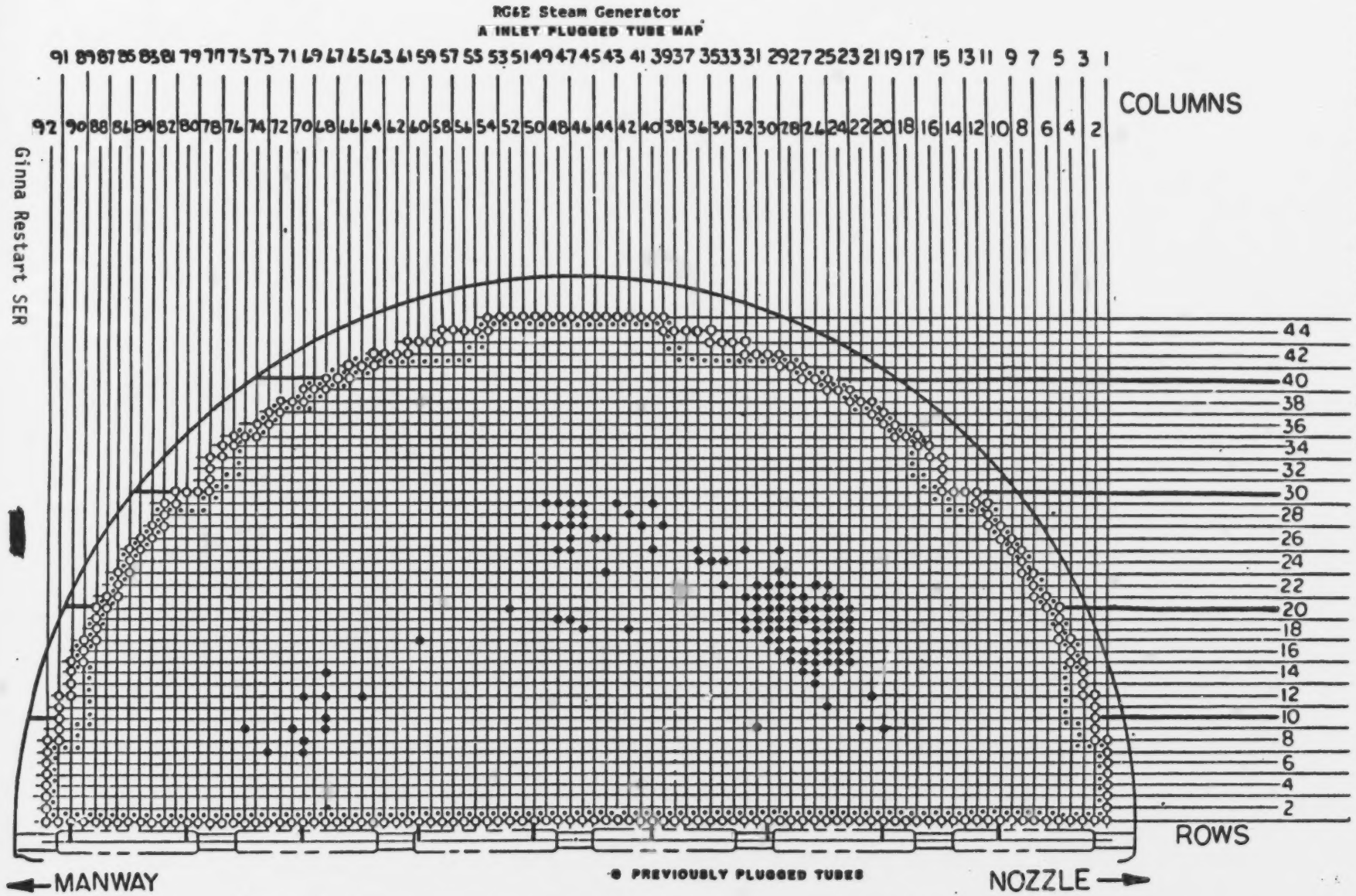


Figure 5-3 Steam Generator "A" Hot Leg Before January 25, 1982 Event

BEST DOCUMENT AVAILABLE

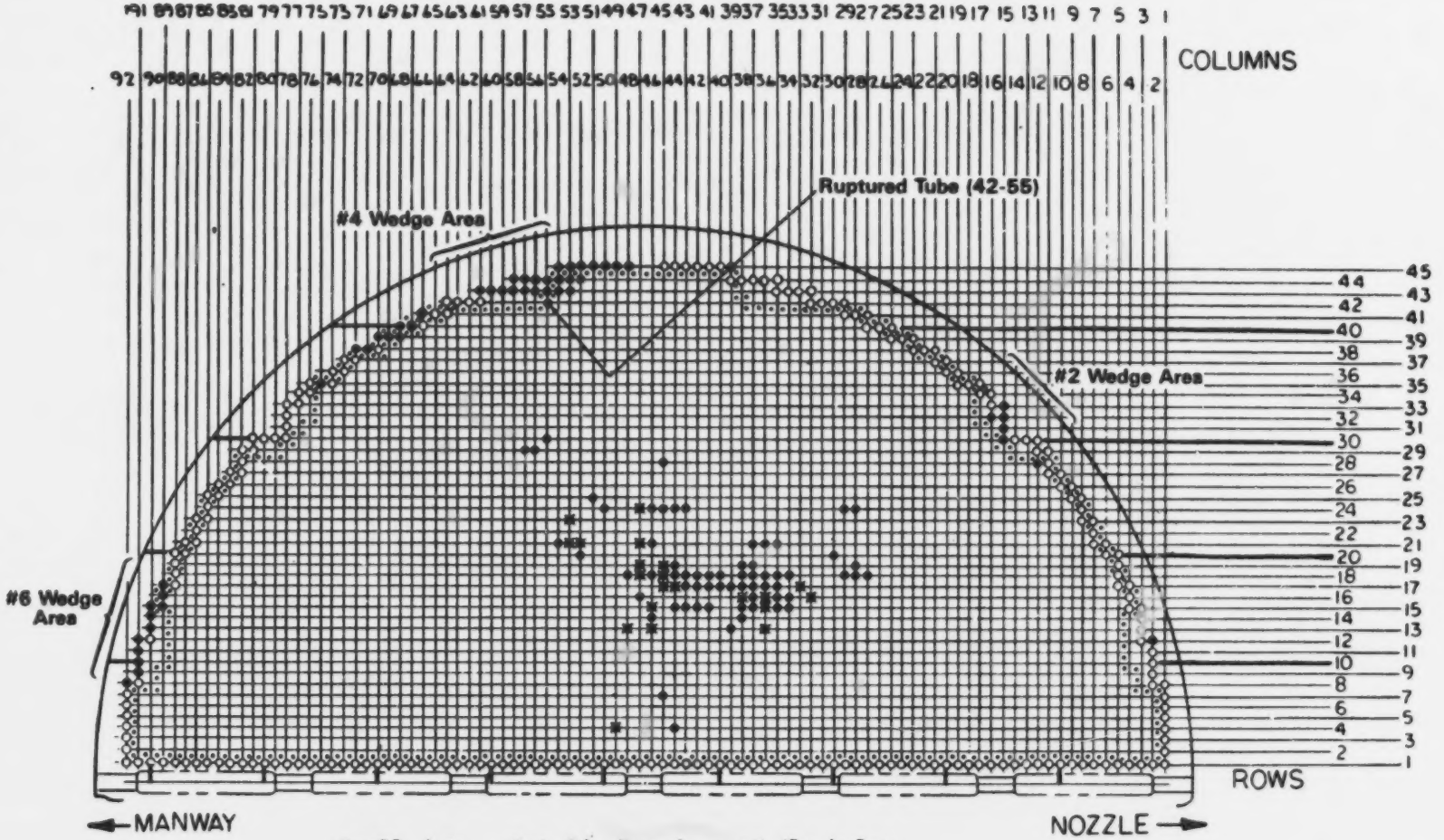


Figure 5-4 **Ginna B steam generator hot-leg tube sheet map before event of January 25, 1982**

BEST DOCUMENT AVAILABLE

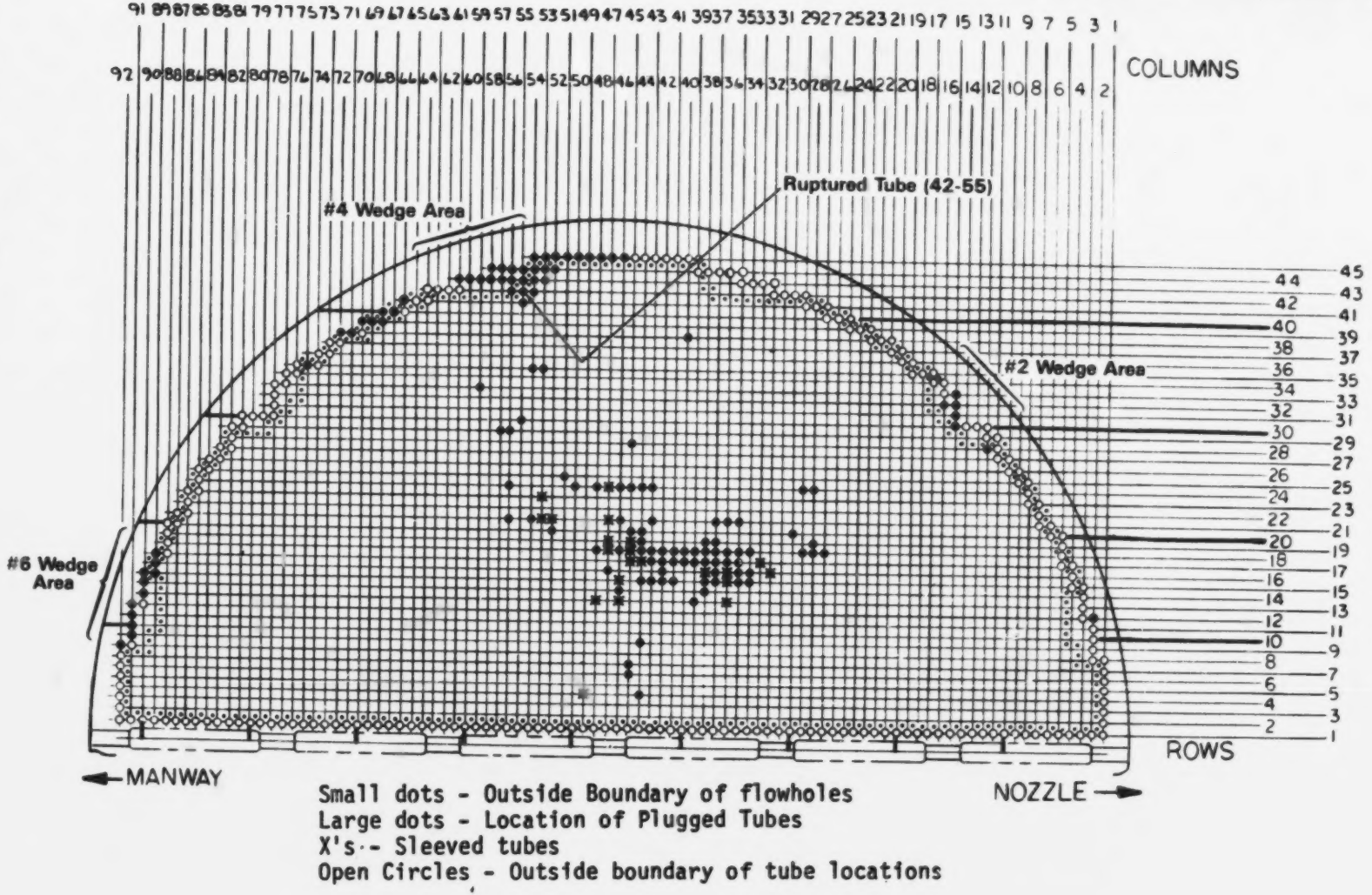


Figure 5.5 **Ginna B steam generator hot-leg tube sheet map as of February 9, 1982**

BEST DOCUMENT AVAILABLE

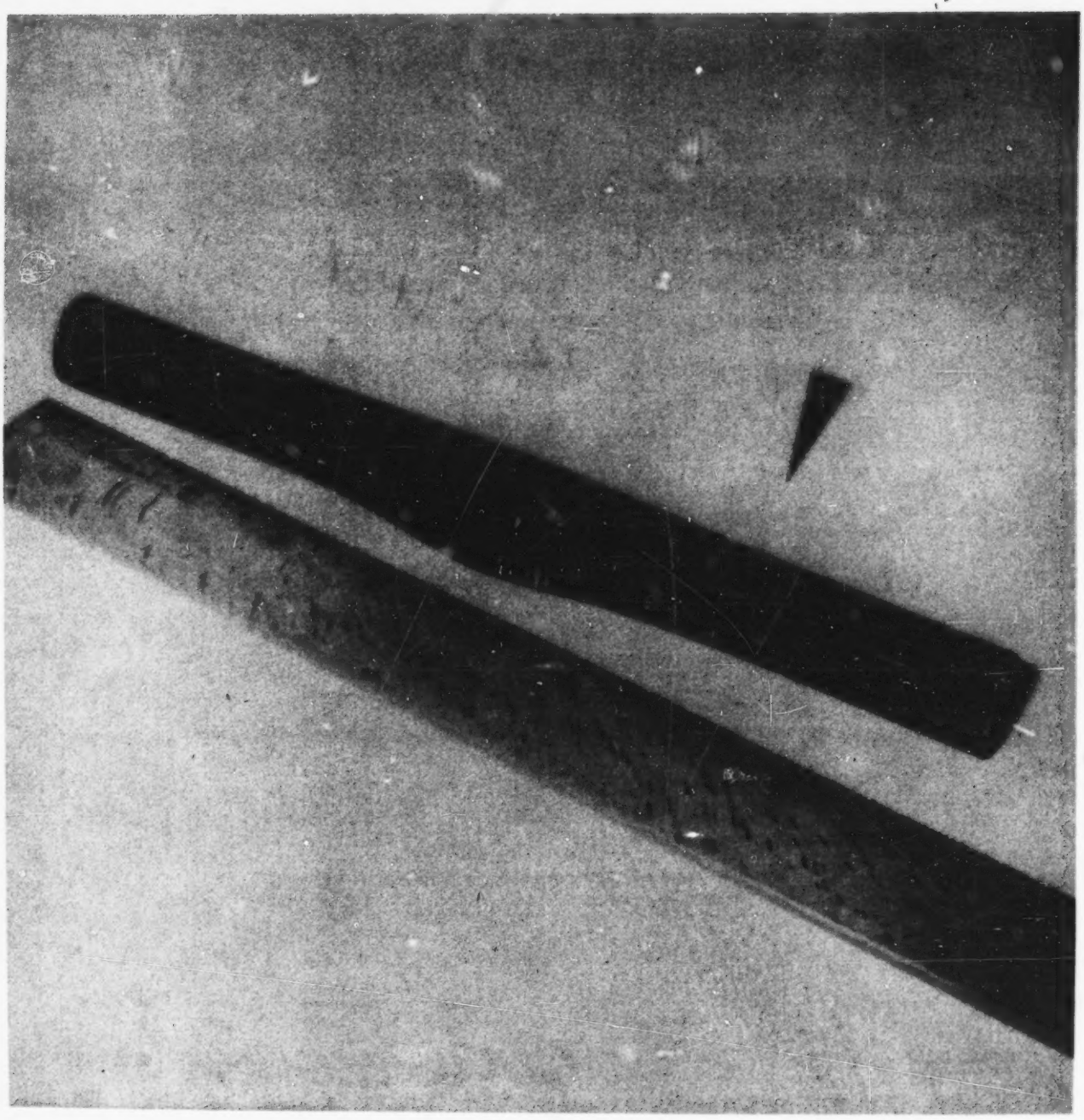


Figure 5.6 Photograph of segment of ruptured tube (R42-C55) removed from "B" steam generator (tube sheet to the right)

BEST DOCUMENT AVAILABLE

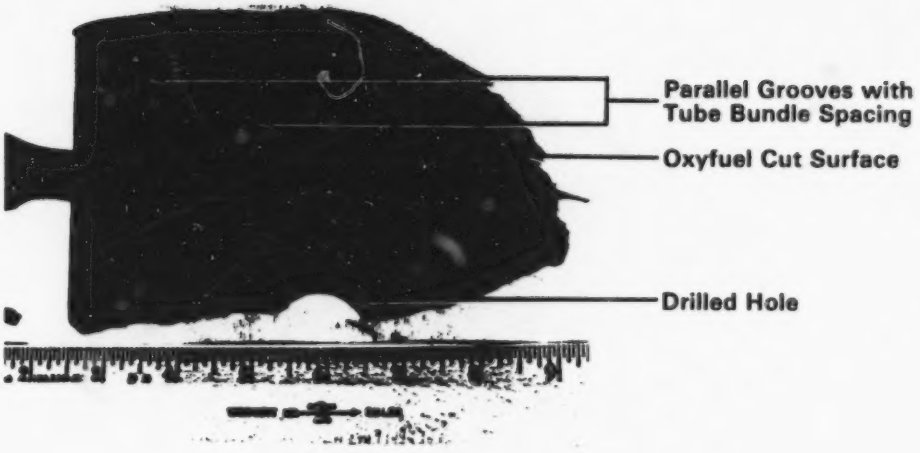


Figure 5.7 **Large foreign object removed from hot leg of B steam generator (½ in. thick)**

BEST DOCUMENT AVAILABLE

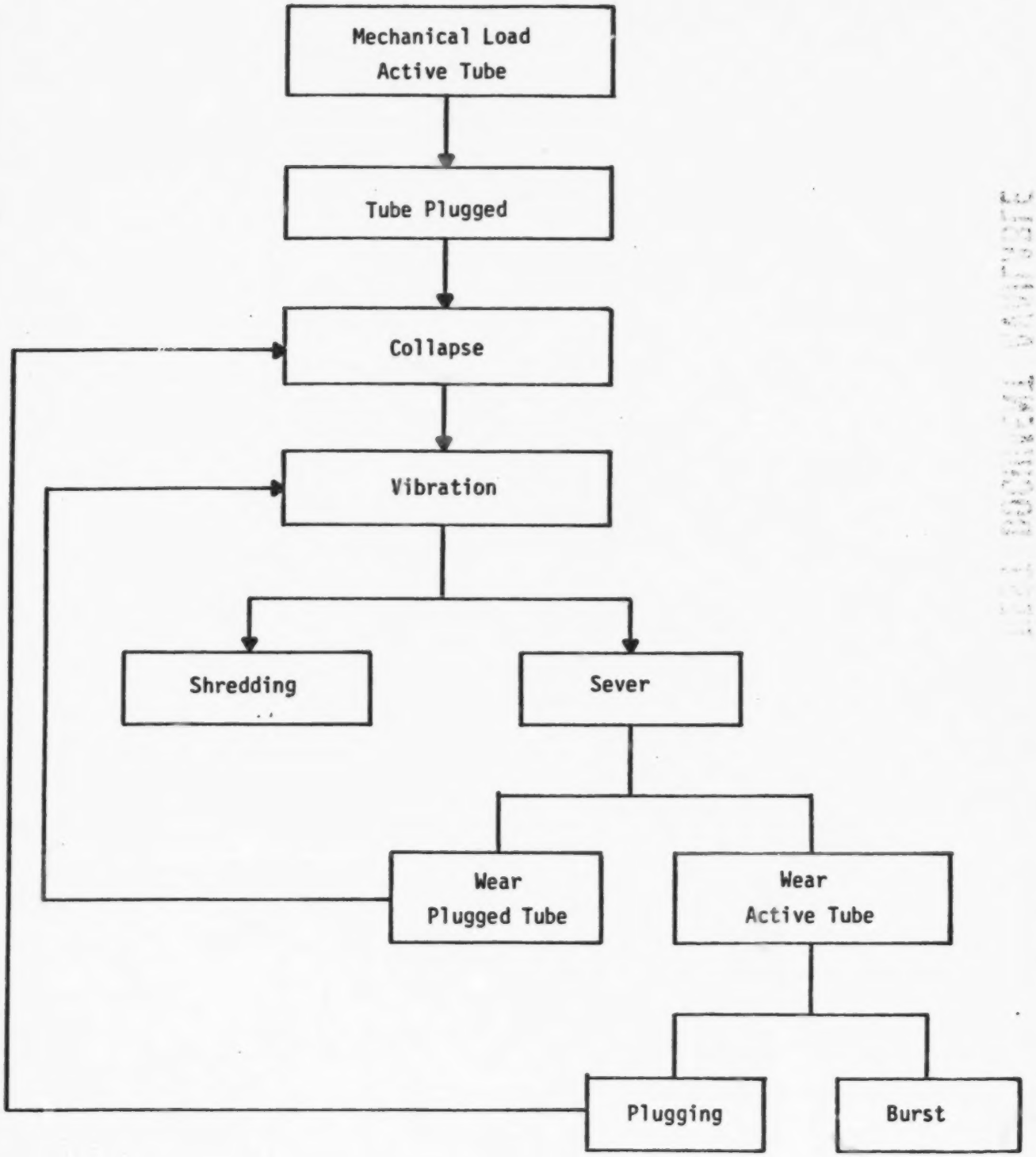
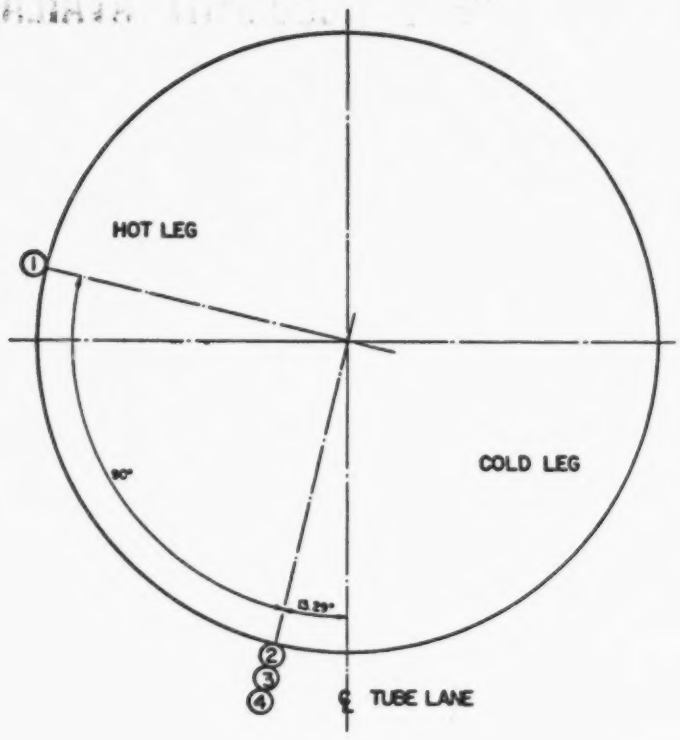
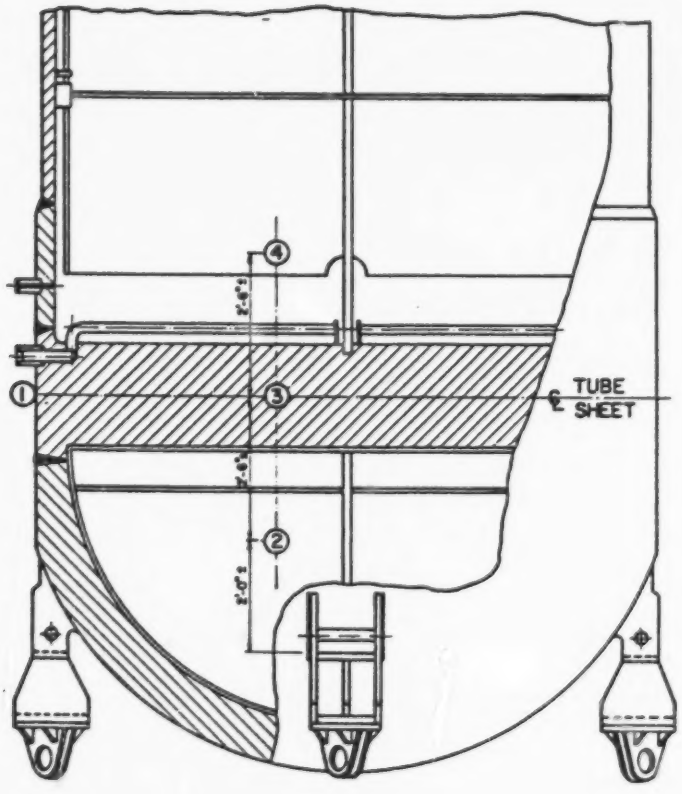


Figure 5.8
Postulated Failure Mechanism Sequence

Ginna Restart SER

BEST DOCUMENT AVAILABLE





S/G LOOSE PART MONITOR SENSOR LOCATIONS

FIGURE: 5.9

REV 4/14/82

6.0 EQUIPMENT DESCRIPTION, OPERATION, AND EVALUATION

6.1 Pressurizer Power Operated Relief Valves

6.1.1 Background

The Reactor Coolant System (Figure 6.1) at Ginna consists of two identical heat transfer loops connected in parallel to the reactor vessel. Each loop contains a steam generator, a pump, loop piping, and instrumentation. Pressure in the system is controlled by the pressurizer, where water and steam pressure is maintained through the use of electrical heaters and sprays.

The pressurizer maintains the required reactor coolant pressure during steady-state operation, limits the pressure changes caused by coolant thermal expansion and contraction during normal load transients, and prevents the pressure in the Reactor Coolant System from exceeding the design pressure. The pressurizer vessel contains replaceable direct immersion heaters, multiple safety and relief valves, a spray nozzle, and interconnecting piping, valves and instrumentation. The electric heaters located in the lower section of the vessel pressurize the Reactor Coolant System by keeping the water and steam in the pressurizer at saturation conditions.

The pressurizer is designed to accomodate positive and negative surges caused by load transients. The surge line is attached to the bottom of the pressurizer and connects the pressurizer to the hot leg of reactor coolant loop B.

Overpressure protection for the pressurizer and the reactor coolant system is provided by the PORVs and the pressurizer safety valves (Figure 6.2). The PORVs prevent opening of the safety valves for mild pressure transients and can be manually opened from the control room. The motor-operated block valve upstream of the PORV provides a means of isolating a stuck-open or leaking PORV. The positions of the pressurizer PORVs and their block valves are

indicated by a discrete set of lights for each valve. The signals for these indications are derived from limit switches that are actuated by the stem of the valves. The PORV positions are also transmitted to the plant computer. The PORVs are not monitored by sonic devices, but the common PORV tailpipe leading to the pressurizer relief tank is equipped with a temperature transmitter detector.

The two PORVs are Copes-Vulcan, 3-in., Model 1513, valves with Model D-100-160 reverse-acting pneumatic operators. Figure 6.3 shows a cutaway view of a PORV. Both PORVs were replaced in 1980 during a modification outage to provide positive valve indication in accordance with TMI Action Plan requirements. Prior to this time, the PORVs had been part of the originally installed plant equipment.

During 1980-1981 the Electric Power Research Institute (EPRI) performed tests on both PORVs and safety valves utilized on Pressurized Water Reactors. The tests were performed on full sized valves under a wide variety of fluid conditions, including steam, transition flow from steam to subcooled liquid, and subcooled liquid. Testing was performed on a PORV of the type utilized at Ginna. The PORV opened and closed on demand in all the test sequences and no damage was observed that would have any affect on valve performance.

In 1979, the reactor coolant system low-temperature overpressure protection system was installed. This system uses the PORVs to prevent overpressurization when the plant is shutdown and at a low temperature with the pressurizer completely filled with water.

Solenoid valves SV-8619A and SV-8619B are used to select the normal or low pressure protection modes of operation by connecting either instrument air or nitrogen pressure to the PORV actuators (Figure 6.2). In normal operation, instrument air supplies the pneumatic pressure for manual and automatic valve control. To open PCV-430, SV-8620A is energized and air flows through SV-8620A and SV-8619A to the PORV activator. To close PCV-430, SV-8620A is deenergized and the actuator line is vented through SV8620A to atmosphere. Control of PC-V431C is similar, using instead SV-8620B and SV-8619B.

BEST DOCUMENT AVAILABLE

In the low-temperature overpressure protection mode, SV-8620A and B are deenergized and PORV position is controlled by SV-8619A and B. To open PCV-430, SV-8619A aligns the nitrogen header to the PORV actuator line. To close PCV-430, SV-8619A aligns the PORV actuator line to the instrument air line and actuator pressure vents through SV-8620A. Again, PCV-431C is controlled in a similar manner.

SV8620A and SV8620B are normally closed, American Switch Company (ASCO) model NP8613A74E, three-way, diaphragm-operated, solenoid, pilot-controlled valves. The vendor has stated that the valves are qualified to standard IEEE-323-1974 requirements for application inside containment. A cutaway view of an ASCO NP8613A74E valve is shown in Figure 6.4. The valve is shown in its deenergized, depressurized condition. If air pressure is supplied to the supply port while the solenoid remains deenergized, the supply side diaphragm shifts to block air pressure to the actuator port. The solenoid core assembly prevents the supply-side diaphragm actuating pressure from bleeding to the exhaust port. It also acts against the disc assembly spring to keep the disc assembly away from the exhaust pilot port, thereby assuring that the exhaust-side diaphragm does not block the exhaust path.

Energizing the solenoid moves the core up, allowing the disc assembly spring to force the disc up until it covers the exhaust pilot port. This allows supply air to flow past the supply-side diaphragm, through the insert assembly, to the exhaust-side diaphragm, then through a hole in the exhaust-side diaphragm to the actuator port. Internal valve pressure then forces the supply-side diaphram open, connecting the supply air directly to the actuator port. The exhaust-side diaphragm then seats as actuator port pressure rises, and flow to the exhaust port causes the pressure differential across the exhaust-side diaphragm open, and the exhaust-side diaphragm closed.

Subsequent deenergizing of the solenoid causes the core to drop. The core pushes the disc assembly downward, venting the exhaust-side actuating pressure through the exhaust port. Further, the core then blocks the vent path through the insert assembly for the supply-side diaphragm actuating pressure. The exhaust-side diaphragm is then pushed open by actuator port pressure, and valve

internal pressure then starts to drop as both the supply air and the actuator port air both flow through the exhaust port. As the internal pressure continues to decrease, supply air flow increses until the differential pressure across the supply-side diaphragm reaches a critical value, at which time the supply-side diaphragm shifts to its closed position, blocking supply pressure to the actuator port. The actuator port continues to bleed to the exhaust port until it has depressurized.

6.1.2. Performance During the Event

During the tube rupture event of January 25, 1982 anomalous behavior was observed on PCV-430, one of the PORVs. Specifically, following the fourth opening of the PORV over a period of 2 minutes, and after receiving a signal to close, the PORV began to close for a period of approximately 2 seconds and then returned to the full open position. The PORV block valve was then closed. The remaining pressurizer PORV, PCV-431C, is identical and was also isolated without being utilized during the incident.

6.1.3 Evaluation

After the plant had been brought to a cold shutdown condition, an investigation was initiated by the licensee to determine the source of the PORV failure. A Failure Mode and Effects Analysis was performed which included the possible effects of spurious electrical signals, mechanical failures, and pneumatic failures. Also, detailed inspections were performed on the PORV and solenoid valve including complete diassembly.

The licensee was assisted by Westinghouse and EPRI personnel who were familiar with the PORV testing program performed for the PWR Utility Owners Group. As a result of this investigation it was determined that the ASCO solenoid valve installed in the PORV air control system (Valve No. SV-8620 A) had been responsible for causing the PORV to resume the open position and remain there.

At that time the licensee also engaged in discussions with the ASCO. The licensee was aware that the exhaust port of solenoid valve SV-8620 A had been

severely restricted to reduce the closing time of the PORV in order to extend the total valve cycle time during any low temperature overpressure transient. This restriction had been installed in 1979 when the low temperature overpressure protection system was installed. The placement of an exhaust restriction on the solenoid valve is in direct violation of the installation and maintenance instructions provided in ASCO Bulletin 8316 which is applicable to valve SV-8620 A.

In order to further determine the details of the apparent anomalous behavior, the licensee performed a series of tests on two model NP 8316 valves. These tests are described in detail in both NUREG-0909 (Ref. 6.1) and the licensee's April 12, 1982 report (Ref. 6.2). The tests were utilized to evaluate (1) the possibility that supply air could bleed to the actuator cylinder and thus actuate the PORV when valve SV-8620 A is in the deenergized mode, (2) the effects of varying exhaust port restrictions on the internal shifting of diaphragms which are essential to proper solenoid operation and (3) the effects of sudden additional rstriction on the solenoid exhaust port.

As a result of these tests it was determined that sudden additional restrictions to the exhaust port could result in the interconnection of all three ports. ASCO pilot-operated solenoid valves contain three ports through which the valve is connected to instrument air, the PORV actuator cylinder and exhaust to atmosphere. A phenomena which connects all three with the exhaust port severely restricted will result in PORV reopening since the plant air supply makeup system will maintain operating pressure on the PORV actuator. It was also shown in the tests that if the exhaust port was substantially restricted, such as if it were to become blocked by debris, it would result in the PORV reopening.

Analytical modelling of the solenoid valve dynamics was also performed for the licensee by Westinghouse personnel. The results of th analysis indicated that the solenoid valve was operating in a "marginally operable" zone with the exhaust port severely restricted. The analysis also showed that additional environmental effects such as small changes in valve body temperature and

small amounts of debris in the instrument air lines would tend to make the valve inoperable.

The staff is in agreement with the licensee that the restricted exhaust port, resulting in a "marginally operable" solenoid valve, and possibly combined with other effects such as thermal transients or foreign debris, was the root cause of the PORV reopening.

To preclude future problems with PORV operation, the licensee has modified the existing air control system of PORV PCV-430 and also that of the other PORV, PCV-431, which also contained a solenoid valve with a severely restricted exhaust port. It should be noted that each PORV air control system utilizes a total of three solenoid valves; two direct acting and one indirect acting. The direct acting solenoids are not subject to the phenomena presented in this report as they do not contain or rely upon the use of internal diaphragms. Therefore, minimum required pressure drops for diaphragm shifting does not pertain to direct acting solenoids. To maintain the required slower PORV closure rate, a check valve with two small holes drilled in the disc has been added between each PORV actuator and its related indirect operating solenoid valve. Strainers have also been added upstream of the solenoid valves in accordance with ASCO recommendations to preclude any deleterious effects from foreign debris.

This arrangement has been reviewed by ASCO and they find it acceptable. Also, the new arrangement has been tested and shown to meet PORV performance requirments.

6.1.4. Conclusion

Based on the detailed staff review of the licensee's proposed modification to the PORV control sytems of both PORVs and a preliminary review of the test results of the EPRI/PWR program for a PORV of the type utilized at Ginna, the staff has concluded that future peformance of the PORV at the Ginna plant will be acceptable.

6.2 Pressurizer PORV Block Valves

6.2.1 Background

In order to allow for isolation of the pressurizer PORVs, each PORV is provided with a separate motor operated block valve (Figure 6.2.) These valves, MOV-515 and MOV-516, are Velan 3" gate valves with Limitorque SMB-000-5 actuators.

6.2.2 Performance During the Event

Operation of the block valves appears to have been completely normal. The full stroke time for PORV block valve MOV-516, the isolation valve for PCV-430, as determined by a sharp increase in pressurizer pressure, was approximatley 35 seconds. No leakage was apparent.

6.2.3 Evaluation and Conclusion

When compared with quarterly stroke time values recorded for Inservice Testing in June, September and December of 1981, closing against blowdown conditions has almost no effect on the closing time of block valve MOV-516. Block valve MOV-515 isolated the remaining PORV (PCV-431C), which was not called on to operate during the event. Although stroke times were not recorded, no anomalies were noted.

In addition, the block valves are stroke tested quarterly and the PORVs are stroke tested during each cold shutdown and refueling outage in accordance with the licensee's Inservice Testing Program, which provides ongoing periodic verification of the performance of these components. The staff, therefore, concludes that the block valves performed as expected and no corrective actions are required.

6.3 B Main Steam System

6.3.1 Background

The main steam system is shown in Figure 6.5. The main steam system supplies steam to the turbine generator, the turbine-driven auxiliary feedwater pump, the gland steam system, the steam dump system, the steam reheaters, and the air ejector. The main steam system is comprised of two lines, A and B, with a steam generator in each line.

Steam from each steam generator flows to the turbine via the main steam line through a flow restrictor, a main steam line isolation valve (MSIV), and a check valve to the main steam header. Steam is directed to the various steam loads from the main header. Each main steam line has one ARV, four safety valves, and one steam supply valve to the turbine-driven auxiliary feedwater pump; all are located upsteam of the MSIV.

The exhaust from the main turbines is condensed in the condenser and collected in the hotwell. The condenser is a large heat exchanger, which operates at a vacuum. Cooling water from the circulating water system flows through tubes, and the condensing steam flows over them. Lake Ontario is the source of the circulating water.

The air ejectors help maintain a vacuum by scavenging noncondensible gases from the condenser. Steam from the main steam header provides the motive power for removing the gases from the condenser. Steam from the air ejector is condensed by a heat exchanger cooled by the condensate system. The noncondensible gases pass through a radiation monitor and exhaust to the atmosphere. Condensate flow must be provided in order for the air ejectors to be operable.

The steam dump system provides a method for creating an artificial steam load to prevent reactor trip during turbine load reductions and to prevent atmospheric steam releases, thereby conserving condensate inventory. The piping for the steam dump system is from the main steam header downstream of the MSIV and the system exhausts to the main condenser through eight dump valves. The control system for these valves has two separate control modes: steam pressure and reactor coolant average temperature (T_{AVE}). The pressure mode is used during startup to 15% power. The operator selects the T_{AVE} mode above 15% power. The control system modulates the dump valves according to the mode control selected.

The rated capacity of the steam dump system is 40% of the plant design steam flow.

In the event that the steam dump system is inoperable, the steam generator PORV and four safety valves located on each main steam line can dump steam to the atmosphere to control steam line pressure. The relief valve will relieve 10% of rated steam flow; it is controlled automatically or manually by the control room operators. The set point for the ARV is normally 1050 psig but can be reduced by operators in the control room. The steam generator safety valves are capable of relieving 100% of maximum calculated steam flow. The first safety valve is set at 1085 psig (system design pressure) and the others are set at a pressure of 1140 psig. Only the relief valve has an isolation valve which can be closed in the event the valve fails open.

The feedwater and condensate systems form a closed cooling water system with full flow polishing (cleanup) capability. These systems are composed of the condenser, three 50% condensate pumps, three 50% condensate booster pumps, four demineralizers (three in normal operation), hydrogen coolers, an air ejector condenser, a turbine gland steam condenser, low-pressure feedwater heaters, two 50% motor-driven feedwater pumps, and two high-pressure feedwater heaters.

6.3.2 Performance During the Event

Prior to the tube rupture at 0925, the plant was operating at 100% power at steady state. At approximately 0928, the reactor tripped on low pressurizer pressure followed by automatic actuation of safety injection. Both main feedwater pumps tripped and both motor-driven auxiliary feedwater pumps started upon safety injection. At this time the B SG level was approximately 11% of the narrow range level. Both reactor coolant pumps were manually tripped at approximately 0929. The turbine-driven auxiliary feedwater pump automatically started at 0929, and at 0932 the B motor-driven auxiliary feedwater pump was manually tripped. The B steam generator main steam isolation valve was closed at 0940 and the turbine-driven and A motor-driven auxiliary feedwater pumps were manually tripped by 0948. At 0954 the B steam generator PORV was manually isolated by closing the block valve. The B SG narrow-range level indicator

went off scale high at approximately 0955 indicating that the moisture separating equipment was beginning to fill with water. To control primary system pressure, the pressurizer power operated relief valve was cycled several times; the last time the valve was cycled it stuck open and primary system pressure dropped to its lowest value (830 psig) during the transient. The block valve was then closed and continued safety injection resulted in increased primary system pressure. Since the B steam generator power-operated relief valve was isolated, it did not open at 1050 psig steam generator pressure. The B steam generator pressure continued to increase causing one safety valve to lift at approximately 1080 psig for the first time. Primary system pressure remained at approximately 1370 psig for several minutes and the steam generator safety valve lifted a second time at 1060 psig SG pressure and a third time at 1055 psig S/G pressure. After the safety valve lifted for the third time and the safety injection pumps were secured and primary system pressure quickly dropped. SG pressure followed primary system pressure and the safety valve lifted for the fourth time at 1035 psig. The safety valve lifted a fifth time at 1030 psig. It should be recognized that each time the safety valve lifted, it lifted at a slightly lower pressure. At some undetermined time, both the steam generator and the main steam pipe completely filled with water.

6.3.3 Evaluation

6.3.3.1 Steam Generator Safety Valve Performance

The following staff evaluation of the Ginna steam generator safety valve performance during licensee shutdown of the facility subsequent to the tube rupture, was based on (1) the Rochester Gas and Electric Company (RGECo) report dated April 12, 1982 (Ref. 6.2), (2) NUREG-0909 (Ref. 6.1) (3) April 29, 1982 telecon between NRC staff and the licensee, and (4) meeting of May 5, 1982 in Bethesda between NRC staff and the licensee.

During shutdown subsequent to the B steam generator tube failure, one of the four ASME Code safety valves (Figure 6.6) mounted on the 30-inch steam line between steam generator B and the main steam isolation valve, opened and closed

five times. The valve that opened has the lowest set pressure and is set to open at 1085 psig. The other three valves are nominally set to open at 1140 psig and did not open. All four valves are the same model, HC-65, and same size, 6R10, manufactured by the Crosby Valve Company.

The licensee reported that the valve opened at 1080 psig on the first opening and each of the subsequent four openings were at a slightly lower pressure, with the last opening at 1030 psig. The licensee provided a technical discussion of the reasons for the progressively lower opening pressures and this included observations of seat degradation that was observed upon inspection of the valve after plant shutdown. In addition, the licensee has provided to the staff a description of the refurbishing that has been performed to all four of the Steam Generator B valves. NUREG-0909 also notes that the valve opened and closed at generally decreasing pressures and discussed a possible reason for the decreasing closing pressures; the possibility of some steam leakage after closing the first time, and water leakage estimated at 100 gpm after the last closing. The NUREG attributed the water leakage to the likelihood of failure to fully reseat after the last closing until 50 minutes later when the valve apparently stopped leaking.

The description of the safety valve performance in the licensee report dated April 12, 1982, and in NUREG-0909 are consistent. However, NUREG-0909 provides more details of seat leakage and describes exposure to two-phase and liquid flow as a possible reason for the decrease in closing pressures. The licensee report describes the reasons for lowered opening pressures as resulting from the increase in temperature of the valve spring due to the valve blowdowns with resulting spring relaxation. Also the licensee reported damage and yielding of the seating surfaces due to cycling of vibrations because of two-phase flow as another reason for lower opening pressures.

At the request of the PWR utilities, the Electric Power Research Institute (EPRI), during 1980-1981, performed extensive tests on PORVs and safety valves representative of those installed on PWR pressurizer overpressure protection systems. The tests were performed on full-size valves representative of those in service on pressurizers in PWR plants. They also were performed for a

variety of fluid conditions including steam, transition flow from steam to subcooled liquid, and subcooled liquid. These tests were performed in response to one of the NRC TMI Action Plan Items, item II.D.1, as clarified in NUREG-0737 (Ref. 6.3). The safety valves tested in this program are very similar in design to those used on the Ginna and other PWR main steam systems.

Based upon inforamtion in NUREG-0909, the licensee's April 12, 1982 report, subsequent discussions with licensee personnel supplemented by a preliminary review of the EPRI valve test results previously referred to, and other information received from safety valve manufacturers, the staff has concluded that the valve behavior was entirely within its design basis. The EPRI test program results have shown that cycling and vibration can occur on two-phase and liquid flow for spring-actuated safety valves, designed primarily for steam service, and can cause damage to the valve seats and that anomalies in closing pressure can occur.

A safety valve is designed is to open and relieve pressure when required. On any subsequent closing, the valve may experience some leakage. This is within current state of the art for this type of overpressure protection device. Due to additional closing and cycling and resulting degradation of the valve seats, the leakage would be expected to increase with subsequent actuations. In addition, dimensional changes in the valve disc and seat due to thermal effects and due to the valve having seating materials designed explicitly for steam service, but then having been subjected to two-phase and liquid flow could contribute to seat leakage.

Additionally, the staff concurs with the licensee that for an open or exposed spring safety valve in which the spring is exposed to the relieving fluid, the capability exists of heating and relaxing of the spring.

6.3.3.2 Thermal and Pressure Effects Across the Tubesheet and Channel Head

The most adverse pressure and temperature differential across the tube sheet and channel head, ΔP and ΔT respectively, have been identified by the licensee. These are primary-to-secondary ΔP of 160 psi and primary-to-secondary ΔT of

15/BEST DOCUMENT AVAILABLE

280°F. This temperature differential is assumed to be very conservative as it assumes the temperature above the tube sheet is about 540°F. The licensee reported that this temperature was close to 400°F due to the cooler water flowing through the leak during the secondary phase of the event. The thermal transient is slow enough so that only the maximum steady-state ΔT requires an evaluation. The most highly stressed region from the above conditions is the secondary face of the tube sheet. The combined stress caused by the pressure and temperature differential is determined to be 45,000 psi.

6.3.3.3 Steam Generator Overfill

The licensee has analyzed the B main steam line subjected to overfill and cooldown conditions. The overfill analysis reflected a water-solid dead-weight condition from the B-generator to the main-steam isolation valve combined with an internal pressure of 1085 psig. A thermal analysis was also performed on this pipe segment assuming a water-filled system and a temperature of 555°F. The dead-weight and thermal analyses were based on Equations 11 and 13 of ANSI B31.1 Power Piping Code, (Ref. 6.4). All piping stresses, both inside and outside containment, were shown to be below the stated material allowables. Although these results were not independently verified, the staff concluded that they appear reasonable and are acceptable.

The loads on the piping supports were also evaluated and subjected to the same loading conditions as above. The licensee stated that the loads on a rod-type hanger, a spring hanger, and two pipe guides exceeded the allowable loads. He stated that the allowable loads have a minimum factor of safety of 3.0 based on yield stress. (This is approximately true for A36 structural steel; however, the actual material was not specified.) The loads in these supports were shown to be less than three times the allowable loads, so that these supports were not stressed over yield. Subsequent visual inspection of these components showed no evidence of damage. These results have not been independently verified, but appear reasonable and are also acceptable.

The analysis also showed that the main steam header anchor bolts were stressed over allowable values for tensile and shear loading, and above the minimum

yield strength of the material. The licensee has replaced these bolts. The staff finds this acceptable.

6.3.4 Conclusions

The performance of the steam generator safety valve that opened was satisfactory. The valve performed essentially as designed in passing steam. Even though it was exposed to two-phase flow and possibly liquid flow conditions, it opened, relieved pressure, and closed. Seat leakage after opening on the first actuation is always a possibility and spring safety valves designed for steam conditions do not generally operate as effectively on liquid.

The B steam generator safety valve that opened and the three other safety valves were refurbished and the set pressure adjusted during startup tests.

Based on an overall review of the reported safety valve performance as stated in the licensee report and in NUREG-0909, and based on subsequent discussions with licensee personnel concerning the valve performance and the refurbishing of the valves, the staff concludes there is reasonable assurance that the B steam generator safety valves will perform their design function and will have no adverse effect on the health and safety of the public.

Based on a review of the licensee's April 12, 1982 submittal, the effects of the pressure and temperature differentials across the tube sheet and channel head are within the structural capability of the components and are, therefore, acceptable. Also the affects of filling the B main steam line pipes with water have been reviewed and found to be acceptable by the staff.

Deformations from this event were elastic and no detrimental consequence to the tube sheet is expected to have occurred. The conservative 280°ΔT will induce discontinuity stresses at this junction from the restraint to radial expansion of the shell by the tube sheet. The licensee has reported that a conservative analysis assuming zero rotation resulted in a calculated maximum stress intensity of 87,900 psi. The staff is in agreement with the licensee that this is a

secondary stress that is self-limiting and a one-time application will not produce any detrimental consequences.

The maximum secondary to primary ΔP exerted an external pressure on the steam generator tubes of 160 psi. This pressure differential is well within the structural capability of the tubes based on both test and analytical data.

6.4 Letdown Isolation

6.4.1 Background

During normal operation, reactor coolant enters the chemical and volume control sytem (see Figure 6.7) via the letdown system. Figure 6.8 shows the valve arrangement for the letdown system as it penetrates the containment. The letdown line is isolated outside the containment by air-operated valve AOV371, which receives an automatic containment isolation signal. Inside containment, the line can be isolated by the use of either the regenerative heat exchanger inlet valve LCV427 or the letdown orifice isolation valves LCV200A, LCV200B, or LCV202. The latter four valves are also air operated. During normal operation operation, AOV371, LCV427, and one orifice isolation valve are open. Valve LCV427 automatically closes on low pressurizer level, and the orifice isolation valves are interlocked with valve LCV427 controls such that they will also automatically close if valve LCV427 receives an automatic closure signal. In addition, on loss of instrument air, valve LCV427 fails open and valves LCV200A, 200B, and 202 fail closed. The letdown orifices reduce the service pressure of the line downstream of them during normal letdown operations; consequently, the design pressure of this piping is less than the normal reactor coolant system pressure. To protect against excessive pressure in the downstream piping, a relief valve is provided. At the time of the event, neither valve LCV427 nor the orifice isolation valves were designed to receive automatic containment isolation signals.

6.4.2 Performance During the Event

The letdown line was isolated at the beginning of the incident on an autmatic containment isolation signal that closed value AOV371. The containment isolation signal also isolated instrument air causing valve LCV427 to fail open and valves LCV 200A, 200B, and 202 to fail closed. Instrument air was restored later, but the selected letdown orifice isolation valve (LCV200B) remained closed and level control valve (LCV427) closed because the pressurizer level was below 10%. Subsequently, the pressurizer level increased and LCV427 and the selected letdown orifice isolation valve opened as designed. The letdown containment isolation valve (AOV371) remained closed, since the valve does not automatically open when the containment isolation signal is reset. Consequently, the letdown line was communicating with the reactor coolant system while the downstream portion of the letdown line remained isolated, and the relief valve (203) opened at a set pressure of 600 psig. This valve relieves to the pressurizer relief tank and was the major contributor to the pressurize relief tank level increase.

6.4.3 Evaluation

Rochester Gas and Electric (RG&E) proposed the following modification to prevent this from recurring. A containment isolation signal is input to the letdown control valve (LCV-427) inside containment. When LCV-427 receives an automatic closure signal, the three orifice valves (AOV-200A, 200B, and 202) are interlocked with LCV-427 such that they will also receive a closure signal.

6.4.4 Conclusion

Based on the review of the Ginna Incident Report, the staff concludes that the proposed modification is acceptable for restart provided the licensee submits a detailed design description and wiring diagrams of the modification and confirms by test after implementation that the valves and circuitry perform their intended function. The licensee has committed to provide such as analysis.

6.5 Effluent Radioactivity Monitoring System

The release pathway for airborne radioactive materials from the R. E. Ginna Nuclear Power Plant to the environment during the steam generator tube failure incident, as shown in Figure 6.9, involved three effluent radioactivity monitoring systems:

(1) The main steam radiation monitoring system, which is designed to detect, indicate, record, alarm, and quantify radioactive materials released from the steam generator PORVs and safety valves;

(2) The air ejector radiation monitoring system, which is designed to detect, indicate, record, alarm, and quantify releases of radioactive materials in noncondensible gases from the secondary system steam via the air ejector and turbine gland seal exhaust; and

(3) The plant ventilation effluent monitoring system, which is designed to monitor radioactive particulates, noble gases, and radioiodines in the ventilation air discharge from the Auxiliary Building.

6.5.1 Main Steam Radiation Monitoring System

The system consists of a collimated energy-compensated Geiger-Mueller detector (Eberline Model SA-11) on each main steam line. The system indicates radioactivity readout locally and in the main control room. A high radioactivity alarm activates the system recorders to start continuous recording of radioactivity in the main steam line and the steam generator PORV and safety valve positions. Radioactivity releases can then be quantified by taking the product of steam flow rate, radioactivity concentration, and the time duration that the valves were open. This system was installed in December 1981 to satisfy the requirements in NUREG-0737, (Ref. 6.3) Item II.F.1, attachment 1, high range noble gas effluent monitor.

During the incident, however, a high radiation alarm setting was not reached and this prevented the system from activating the recorders. Later attempts to

retrieve the data from the monitoring data processing system also failed due to a malfunction of the monitor during the incident. The licensee states in his incident evaluation report that the monitor malfunction is believed to have been due to a small smudge of dirt or residue which caused electrical leakage on a printed circuit board. In addition, the steam generator PORV and safety valve position monitoring function also failed during the incident. The licensee states that inadequate adjustment of the new actuator rods installed on the safety valves, and open sliding links on terminal blocks in the relay room for the PORV, caused the inoperability of the valve position monitoring.

The staff has no unresolved safety concerns prior to plant restart; however, within three months subsequent to the plant restart, the staff will complete the review of (1) the adequacy and basis of the monitor high alarm setpoints, (2) the monitor operability surveillance program, (3) the monitor ranges and sensitivity with respect to their capability to cover the entire range of effluents from normal (ALARA) through accident conditions, and (4) procedures or calculative methods to be used for converting monitor readings to release rate per unit time.

6.5.2 Air Ejector Exhaust Monitoring System

The system consists of two radiation monitors: the R-15 monitor and the SPING R-15A monitor. The R-15 monitor is a sodium iodide detector (Victoreen Model No. 843-03) mounted on the outside of the 8-inch-diameter exhaust pipe and has been in service since 1979. The monitor has a range of 10^2 to 10^6 cpm gamma radiation (equivalent to 0 to 0.1 μCi/cc). The response of this monitor is recorded on a strip chart and also fed to a computer.

During the incident, the strip chart recorder for the R-15 monitor went off scale for 105 seconds beginning at 0926 on January 25, 1982.

The SPING R-15A monitor (Eberline Model SPING-4) is a high range monitor and has three sensitivity ranges with a separate detector for each range.

Range	Detector	Range, μCi/cc
Low	beta scintillation	10^{-6} to 0.05
Middle	compensated GM tube	2.8×10^{-5} to 10
High	compensated GM tube	0.03 to 10^{5}

During normal operation, only hourly averages of the monitor readouts are printed out with the capability of providing an instantaneous readout on demand. Only a high radiation alarm activates the system to provide 10-minute average readouts and recordings. This monitor was installed in December 1981 to satisfy the requirements in NUREG-0737, Item II.F.1, Attachment 1, noble gas effluent monitor.

During the incident, the SPING R-15A low range monitor actuated a high radiation alarm and is suspected to have been off scale after activating the SPING R-15A middle range monitor. However, while the low range monitor was off scale, no 10-minute average radiation readouts or recordings were obtained from the SPING R-15A middle range monitor because a high alarm setpoint was not reached and this prevented the system from activating the recorder. Subsequent to the incident, the licensee made corrections on these alarm point settings such that an alarm on the low range monitor actuates the 10-minute average readouts on the middle range monitor.

The staff has no unresolved safety concerns prior to plant restart; however, within three months subsequent to the plant restart, the staff will complete the review of (1) the adequacy of readouts and recording capability, (2) the adequacy of all monitor alarm setpoints, (3) the monitor operability surveillance program, (4) the procedures or calculative mthods to be used for converting the monitor readouts to release rate per unit time and (5) the need to provide a continuous and instantaneous indicator-recorder (strip chart) in addition to the 10-minute average readouts in the computer to indicate release rate of airborne radioactive materials from the air ejector exhaust to the environment.

6.5.3 Plant Ventilation Exhaust Monitoring System

The monitoring system consists of radioactive particulate, noble gas, and radioiodine detectors. A continuous sample is drawn from the main exhaust vent stack. The system has been in service since the plant startup. These monitors functioned properly throughout the tube rupture incident and provided important information regarding the timing and amounts of radioactivity releases due to the safety valve liftings. The intake for supply air to the Auxiliary Building is located on the roof of the Auxiliary Building at a point which was, most of the time during the incident, downwind from the safety valve releases. Therefore, the plant vent monitors detected the radioactivity released from the safety valve drawn into the Auxiliary Building through the supply air intake. The monitor readouts reflected the time and duration of the safety valve liftings and releases. The adequacy concerning the location of supply air intake to the Auxiliary Building is discussed in Section 8.8.

6.6 Sump A Level Indication

6.6.1 Background

All floor drains in containment drain to containment sump A which is located at the low point in containment, below the reactor vessel (see Figure 6.10). The sump has two level indicators.

6.6.2 Performance During the Event

Early in the incident (1400 hours on January 25) one indicator registered 9.5 ft while the other registered 5.5 ft. At that time, all actions were based on the higher reading. Although no water was removed from the sump, the readings at 0950 on January 26 were 7.5 ft and 5.5 ft, respectively. A comparison was then made between the inputs and outputs of the Sump A level instrumentation racks to determine the source of the discrepancy. The problem was traced to one of the vertical scale indicators on the control board which was responding sluggishly due to static charge buildup on the cover. When discharged by a

technician, the two indicators read 5.3 ft and 5.5 ft, respectively, which is within tolerance for the 30 ft instrument span.

6.6.3 Evaluation

The licensee has stated that a static charge occasionally builds up on the clear plastic covers of an indicator inducing an opposite charge on the indicator pointer and interfering with normal motion. RG&E proposes a program to prevent static buildup by periodically (once a week) applying an antistatic spray to the Foxboro vertical scale indicator covers. The other indicator scale covers in the control room are not susceptible to static charge buildup.

6.6.4 Conclusion

The staff finds that a program of weekly application of antistatic spray to the Foxboro verticle scale indicators is an acceptable solution.

6.7 Safety Injection Pump 1C Auto Transfer Scheme

6.7.1 Background

Safety Injection Pump (SI) 1C is one of three 50% capacity safety injection (high head) pumps provided for emergency core cooling functions. The other two SI Pumps, 1A and 1B, are powered from electrical distribution trains A and B respectively. An automatic load transfer scheme is utilized to power SI Pump 1C from either train A or train B.

6.7.2 Performance During the Event

Because the present design has a time delay of 5 seconds in sequencing SI Pump 1C to train A power and 7 seconds when sequencing it on train B power, the licensee believed that this pump would always sequence on train A power first whenever it was available. During the SG tube rupture incident, however, safety injection pump 1C sequenced onto train B even though both A & B train power was available following the safety injection actuation signal.

6.7.3 Evaluation

Subsequent analysis performed by the licensee revealed that the selection of trains is not dependent on the time delay contacts of the sequencing relays but rather on their instantaneous contacts. Because the train A and train B sequencing relays are energized simultaneously on offsite power the selection of train power for safety injection pump 1C is dependent on the result of a race condition between the two time delay relays. A modification to establish a fixed loading sequence is currently under review by the licensee. We believe that this modification will improve the transfer logic and also eliminate the uncertainty with regard to this pump's power train auction.

Automatic load transfer schemes between redundant safety trains are unacceptable pursuant to Regulatory Guide 1.6 (Ref. 6.5). The staff's concern is that the automatic load transfer scheme will compromise the independence of the redundant safety trains. The transfer logic at Ginna utilizes electric interlocking between the SI pump 1C train A and train B load sequencing relays, as well as between the pump 1C circuit breakers. This, together with the different time delays (5 sec. and 7 sec.) of the sequencing relays, prevents paralleling of the redundant trains through the SI pump 1C circuit breakers. The design meets the single failure criterion and is an acceptable alternative to R.G. 1.6 recommendation as a means of insuring against paralleling of redundant safety trains in an operating reactor.

Another staff concern with regard to the automatic load transfer design is that a fault occurring at the load may be transferred to the redundant safety train, challenging the overcurrent protection of both trains, thereby creating a potential for a possible loss of both trains. The transfer scheme at Ginna utilizes coincident undervoltage signals taken from bus undervoltage relays to transfer safety injection pump 1C to the alternate safety train on a low bus voltage condition. The licensee provided an analysis (Ref. 6.6) which shows that for any level of fault current on the safety injection pump, the SI pump circuit breaker will trip first and remove the fault before the undervoltage relaying will actuate to transfer the fault to the redundant train. The

analysis also showed that there was good coordination (at least a 2.5 to 1 margin) between the SI pump circuit breaker and the upstream bus feeder breaker such that for all levels of fault currents the SI pump circuit breaker will open first to clear the fault before the bus feeder circuit breaker opens. The fault current and undervoltage protection schemes at Ginna meet the single failure criteria; however, the design does not incorporate a lockout design feature to prevent automatic transfer of the fault at the load to the redundant bus on a subsequent undervoltage condition. We have discussed this aspect of the transfer scheme design with the licensee and he has verbally agreed to modify the present design to preclude automatic transfer of the SI pump 1C between redundant trains under fault conditions. We will require that this modification be implemented prior to startup from the next refueling outage.

6.7.4 Conclusion

The staff concludes that the operation of the plant with present design is justified on the basis that it is unlikely that there would be an accident that would require SI simultaneously with a fault on the SI pump 1C occurring during the next fuel cycle. The staff will review the design modification and other provisions to be proposed by the licensee to assure that adequate independence is maintained between redundant trains for all events.

6.8 Use of Non-Safety Equipment

6.8.1 Background/Performance During the Event

Operators are expected to use the best means available to them to safely cope with an event, regardless of the safety classification of the equipment utilized. During recovery from this steam generator tube rupture event, operators used a variety of equipment classified as non-safety-related which, in general, functioned without problems. In most instances, non-safety-related equipment was backed up by safety-related equipment that could provide the same function or effect, if the non-safety-related equipment was unavailable.

During this event, operators relied upon three sets of non-safety-related instruments which did not have safety-related backup during certain periods of the event; i.e., reactor core exit thermcouples during the period reactor coolant pumps were tripped and natural circulation had not been verified; the reactor vessel upper head region thermocouples during the period reactor coolant pumps were tripped; and reactor coolant loop wide-range pressure instrumentation during the period following initial depressurization below 1700 psig. These instruments were used to track the course of the event and to verify adequate core cooling. After the initial depressurization, the wide-range loop pressure instrument provided the only direct indication of reactor coolant system pressure in the control room, other than the non-safety-related computer, for the range of pressures experienced during the event. The process computer failed for 16 min. during the event and is discussed in section 6.9.

6.8.2 Evaluation

RG&E has committed to install and have operational a fully qualified wide-range primary coolant pressure transmitter prior to restart. Core exit and upper head region thermocouples are included in post-TMI Requirments, NUREG-0737 (Ref. 6.3), Item II.F.2, (Instrumentation for Detection of Inadequate Core Cooling). This item is being pursued as a generic upgrade for operating plants.

6.8.3 Conclusion

The staff has found that the proposed installation of a fully qualified wide-range primary coolant pressure transmitter is acceptable provided the licensee submits a detailed design description of the modification and confirms by test after implementation, that the wide range pressure pressure transmitter performs as intended.

6.9 Process Computer

6.9.1 Background

The computer system, a Westinghouse PRODAC 250, is a dedicated real-time system consisting of a central processing unit with parametric inputs from the reactor coolant system, the secondary system, and auxilliary service systems throughout the plant. These inputs are stored as discrete, addressable data points which are used to perform specific computations (e.g., compute subcooling margin), generate alarms, indicate digital and analog information, and to provide pre-trip and post-trip data. The computer was designed to read and record information important to the normal steady-state operation of the plant. The computer system design is not well suited to post-accident evaluation requirements since it does not record parameters such as safety-injection flow, safety system tank levels, and safety system valve position.

6.9.2 Performance During the Event

During the event the process computer failed for 16 minutes. At this time, the cause of the process computer failure is not known. When the computer failed it was deemed more important to restart the computer than to investigate the cause and in this process information which may have revealed the cause of failure was lost.

6.9.3 Evaluation

The licensing basis was that the process computer is non-safety related and not required for post-accident monitoring. While the computer may be an aid to the operator, it is not required to comply with the General Design Criteria of 10 CFR Part 50, or to provide the operator, on a real time basis, information he needs to safely cope with transient and accidents. The requirements for the Emergency Response Facility and Capability which include the Safety Parameter Display System (SPDS), are included in post-TMI Requirements, NUREG-0737, (Ref. 6.3) Item I.D.2 and Regulatory Guide 1.97 (Ref. 6.7). With the implementation of these requirements the operators will be provided in one location an engineered display with critical plant variables to aid them in rapidly determining the safety status of the plant.

6.9.4 Conclusion

The staff does not require any changes to be made to the process computer prior to restart.

6.10 Subcooling Meter

6.10.1 Background/Performance during the event.

The reactor coolant loop subcooling meter design was such that the indicated subcooling value was correct when T_{hot} was above 500°F. When T_{hot} was below 500°F, the meter Thot indicated half the actual value. The only display of Thot was on the computer. This condition required the operator to remember to check T_{hot} and then perform a mental T_{hot} conversion on the displayed subcooling value. The reactor coolant loop subcooling monitors used two different calibrations, one for T_{hot} above 500°F and one for T_{hot} below 500°F. This condition resulted in a display on a single vertical meter of actual subcooling when T_{hot} was above 500°F, and one-half actual subcooling when T_{hot} was below 500°F.

Operators were reminded of this calibration logic by a small sign below these meters; but operators had to be aware of actual T_{hot} to correctly interpret these readings. The T_{hot} parameter was only available on a T_{hot} computer printout which is not located near the subcooling monitors. During the tube rupture event, at least one licensed operator did not correctly interpret these meter readings and reported one-half actual subcooling values when the information was requested.

6.10.2 Evaluation

RG&E indicated that during calibration of the RCS subcooling meter, it was discovered that the monitor indicates 1/2 of the actual margin when below 500°F

and indicates the actual margin above 500°F. Interim procedures were in place at the time of the incident which ensured that the operators obtained the actual subcooling margin from the meter indication. This has been corrected so the monitor indicates the actual subcooling margin.

6.10.3 Conclusion

The staff agrees with the licensee's actions to correct the monitor so that it indicates the actual subcooling margin at all times.

6.11 References,

6.1 NUREG-0909, NRC Report on the January 25, 1982, Steam Generator Tube Rupture at R.E. Ginna Nuclear Power Plant, April 1982.

6.2 Incident Evaluation, Ginna Steam Generator Tube Failure Incident, January 25, 1982, R.E. Ginna Nuclear Power Plant, Docket No. 50-244, April 12, 1982.

6.3 NUREG-0737, Clarification of TMI Action Plan Requirements, November, 1980.

6.4 ANSI B31.1 Power Piping Code, Summer 1973 Addenda.

6.5 US Atomic Energy Commission, Regulatory Guide 1.60, Design Response Spectra for Seismic Design of Nuclear Power Plants, Rev 1, December, 1973.

6.6 Rochester Gas and Electric, Design Analysis 6, IC Safety Injection Suing Pump Transfer Scheme, Docket 50-244, May 3, 1982.

6.7 US Nuclear Regulatory Commission, Regulatory Guide 1.97, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Rev 2, Dec 4, 1979.

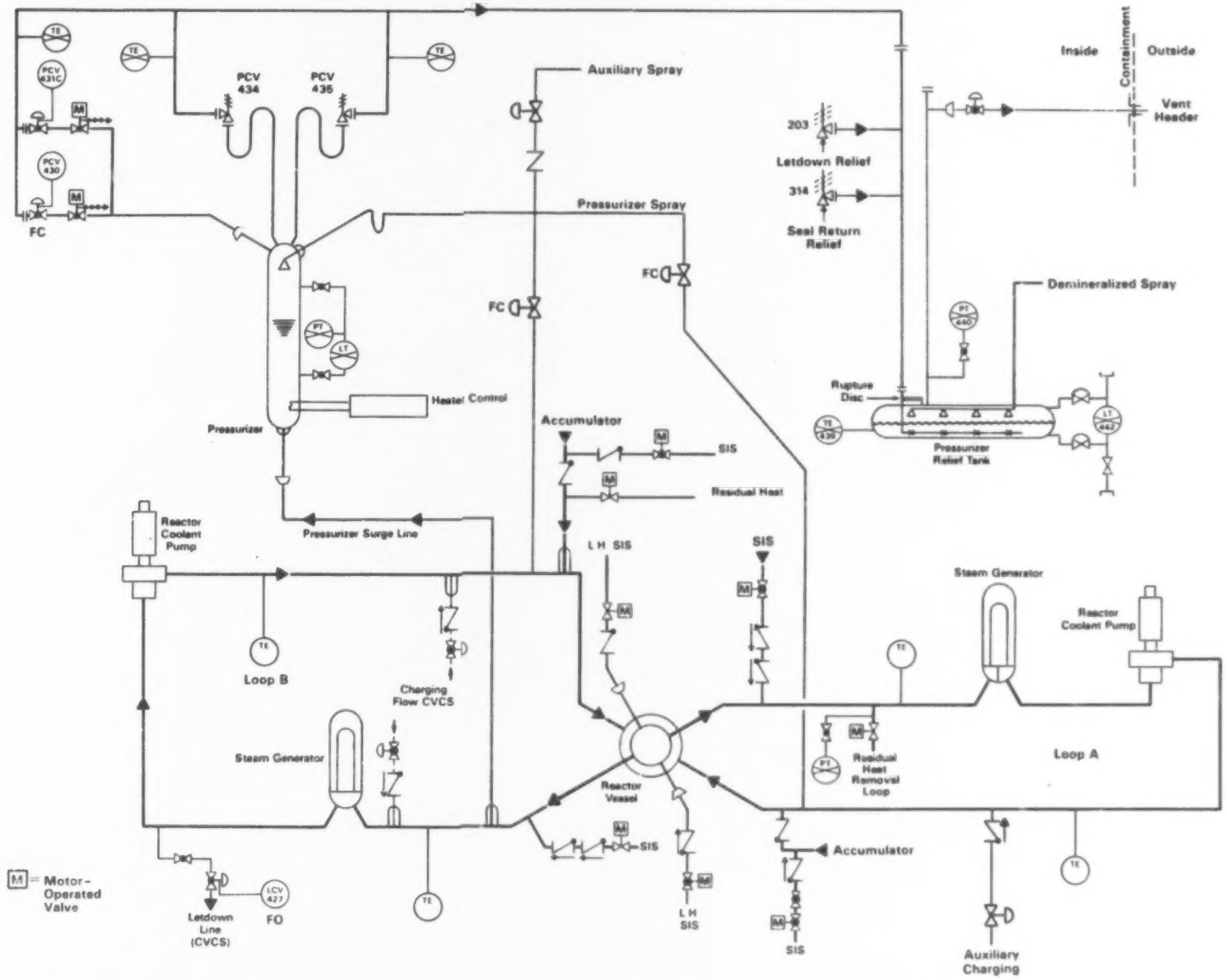


Figure 6.1 Ginna Primary Coolant System Diagram

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

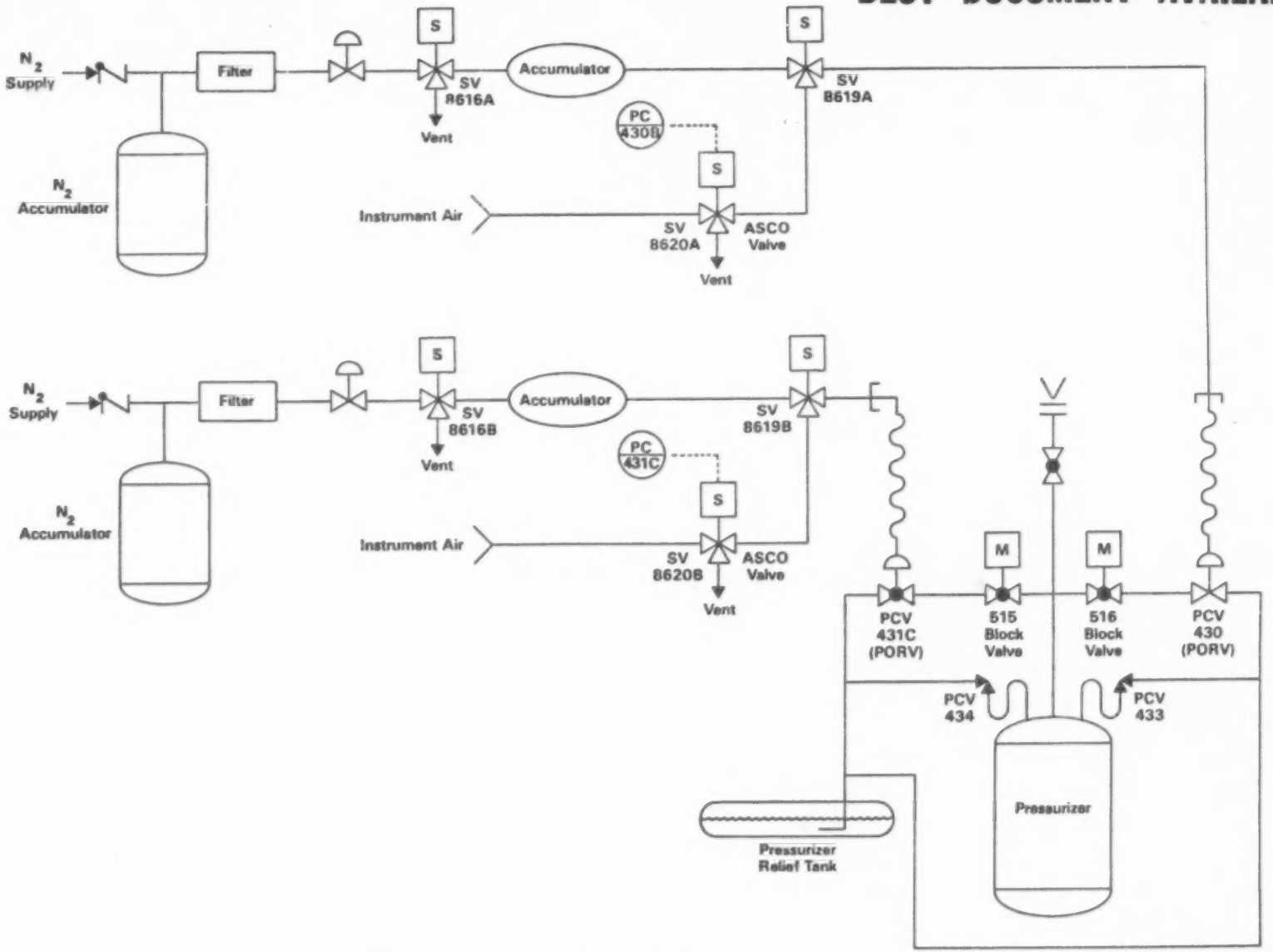
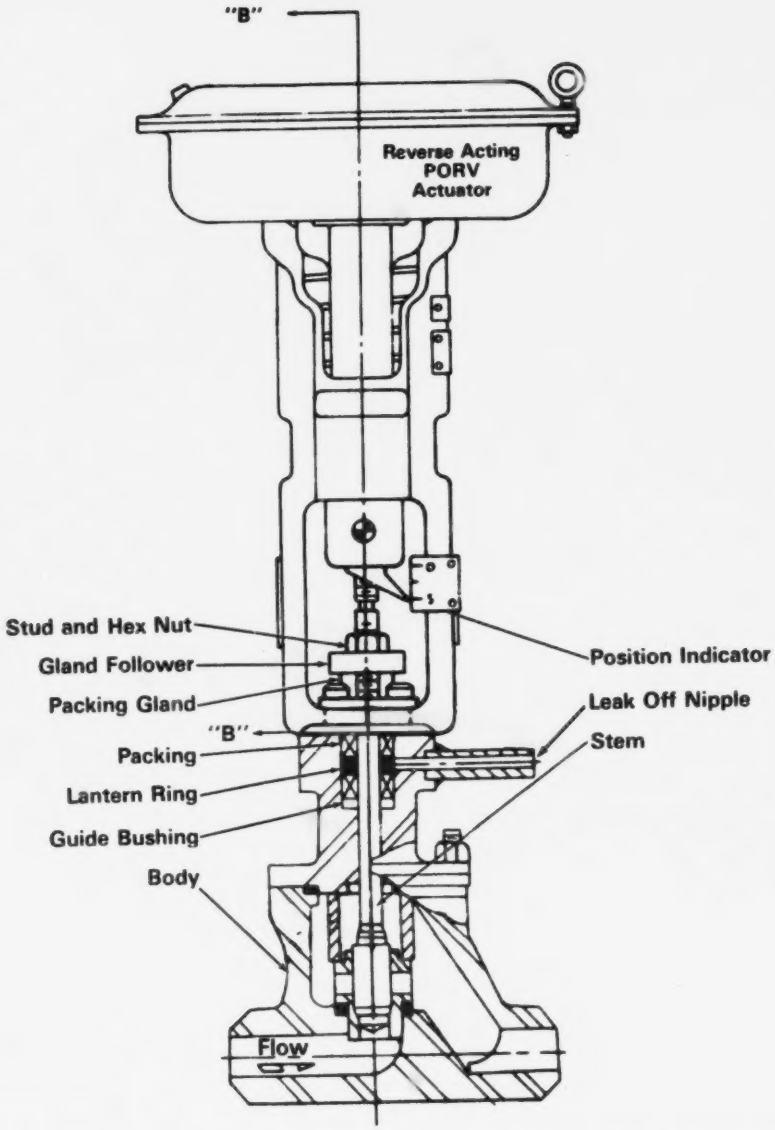


Figure 6.2 Simplified reactor coolant system overpressure protection system



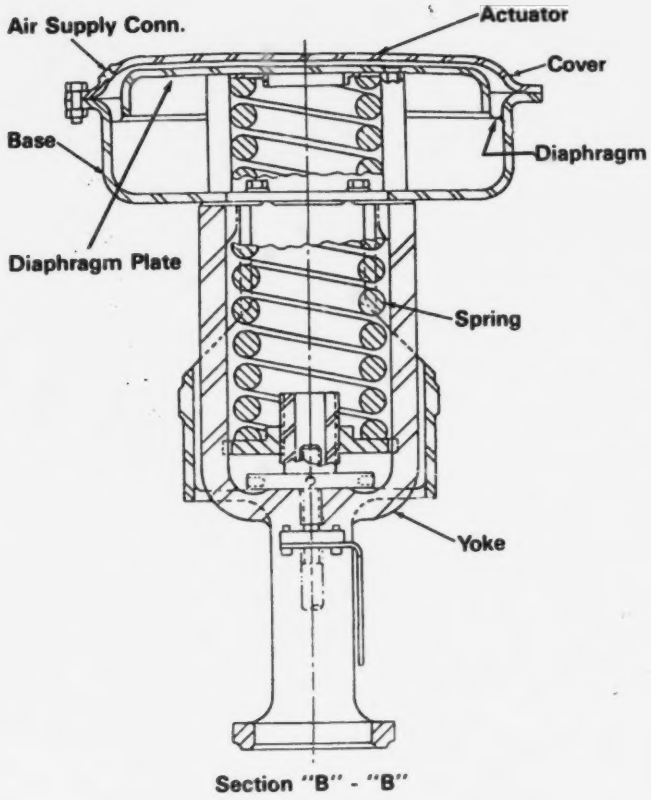
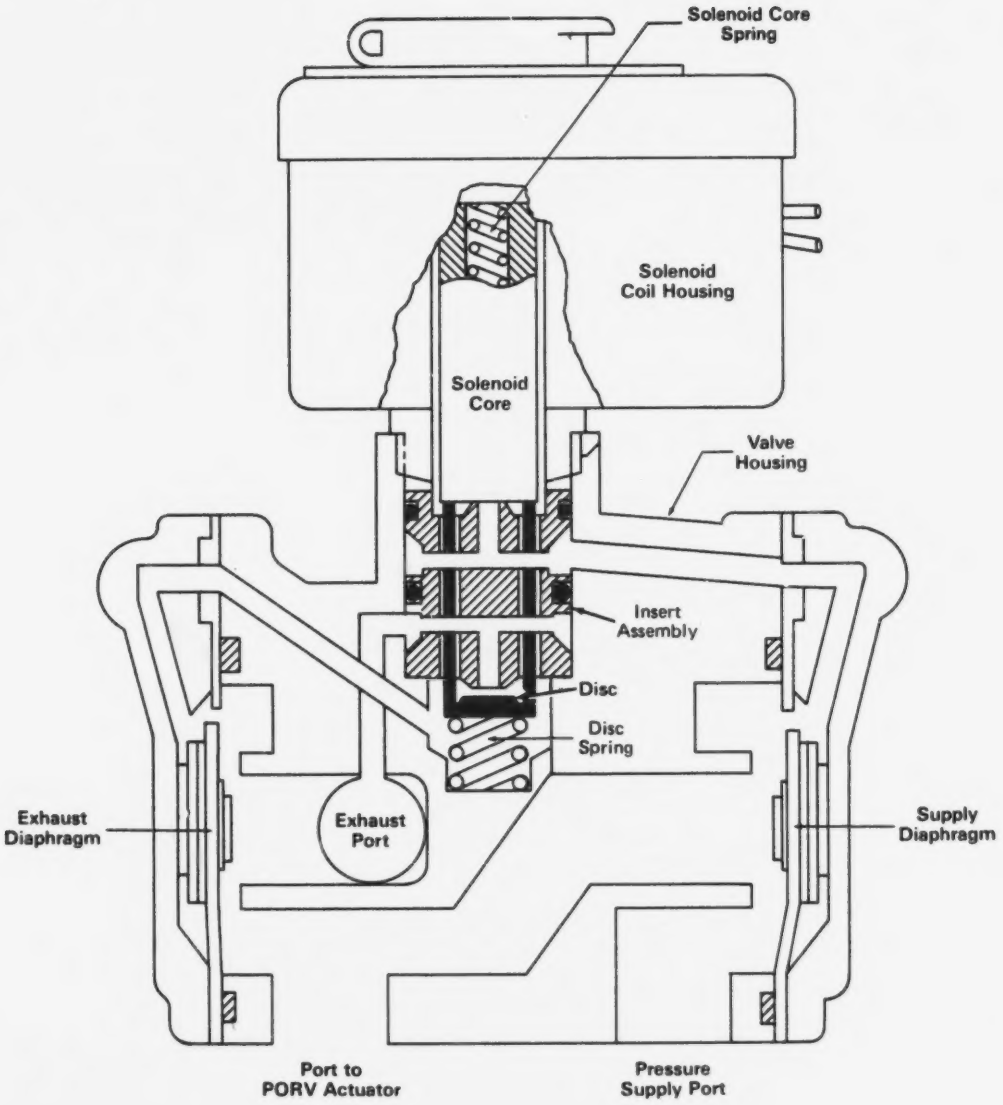


Figure 6-3 Copes Vulcan Pressurizer PORV

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE



NOTE:
(Shown without air pressure or electricity)

Figure 6-4 ASCO three-way diaphram solenoid valve

BEST DOCUMENT AVAILABLE

Ginna Restart SER

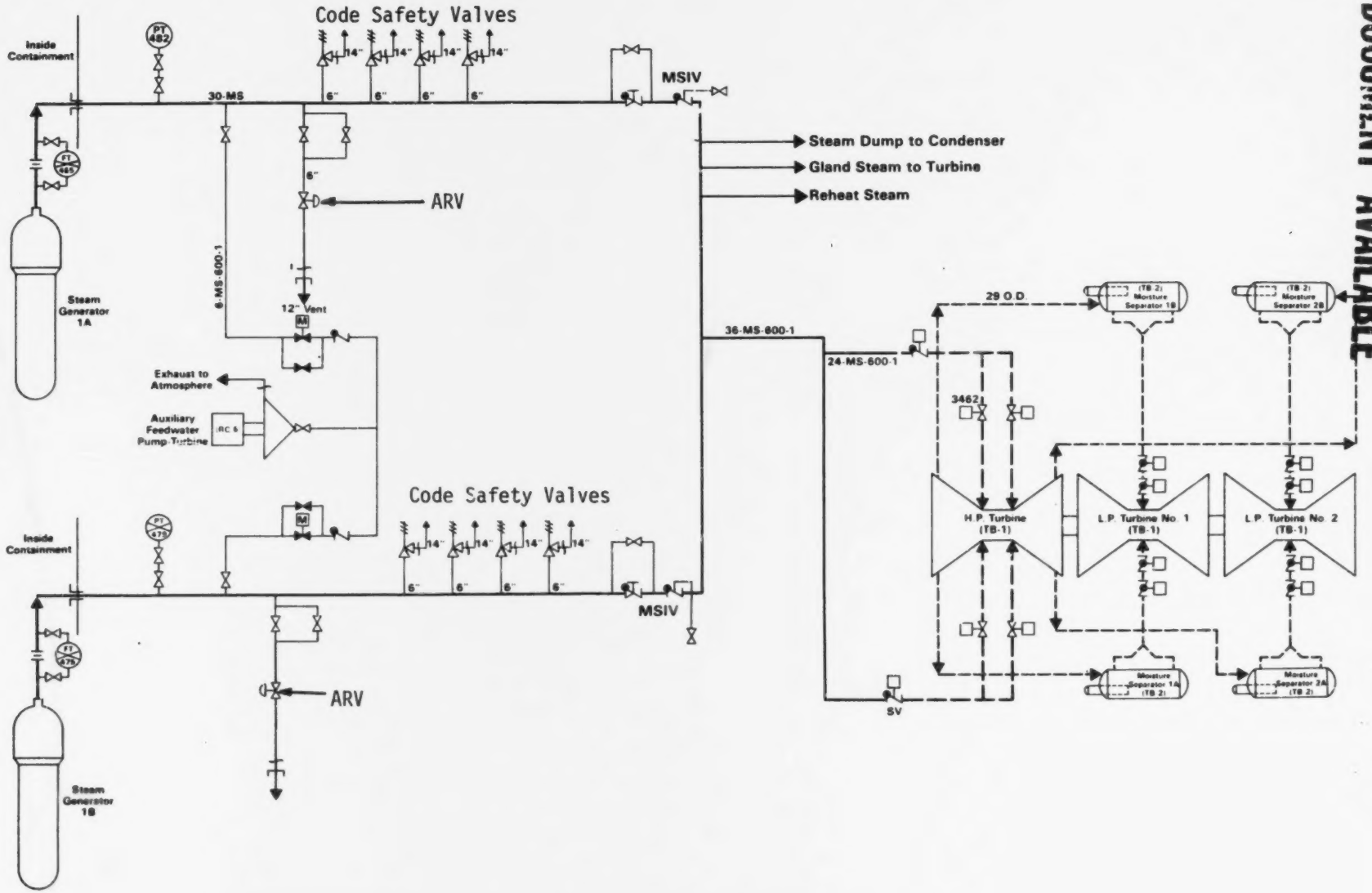


Figure 6.5 Flow Diagram of Main Steam and Reheat System

BEST DOCUMENT AVAILABLE

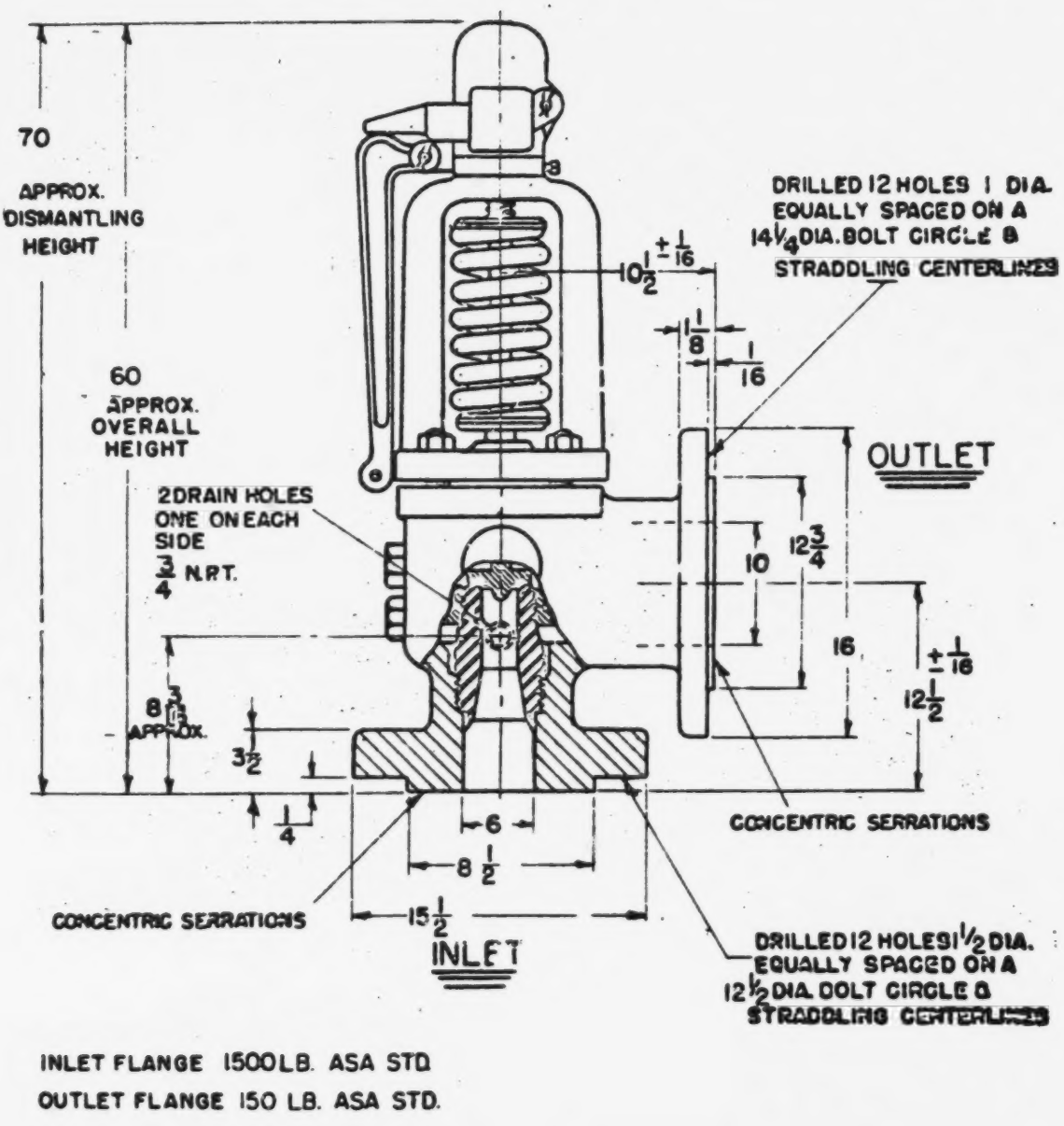


Figure 6-6 Steam Generator ASME Code Safety Valve

Ginna Restart SER

BEST DOCUMENT AVAILABLE

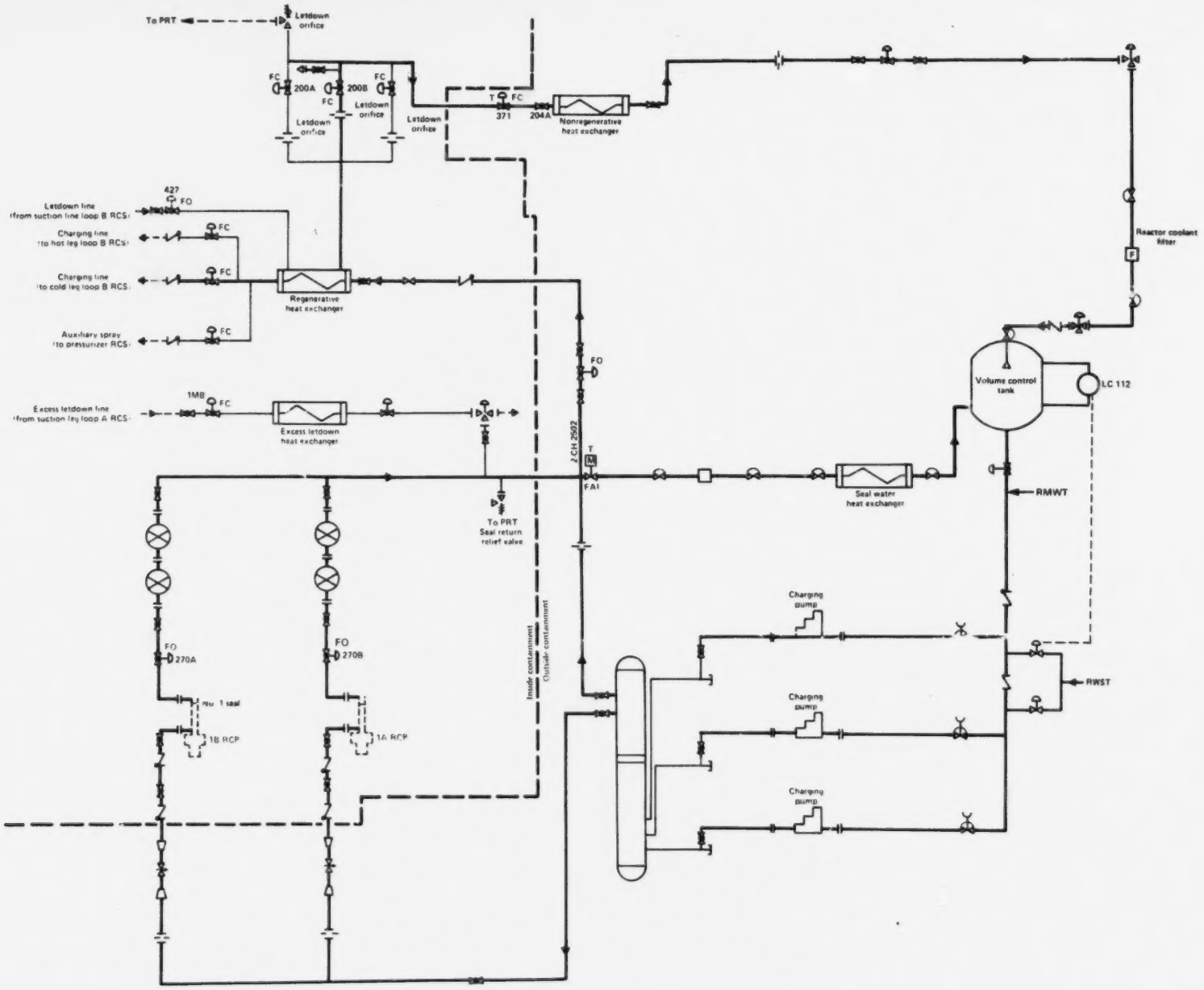


Figure 6-7 Chemical and Volume Control System

BEST DOCUMENT AVAILABLE

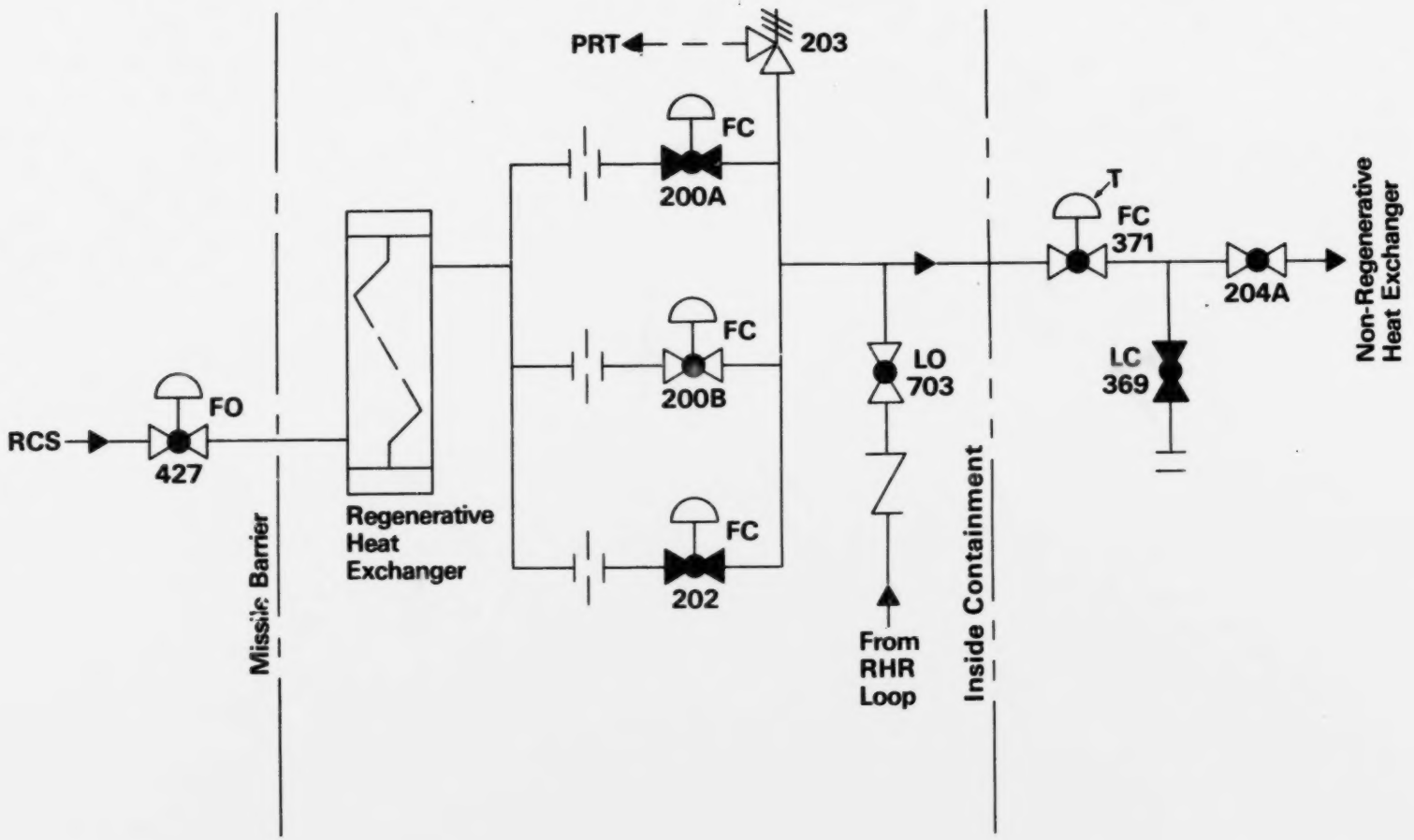


Figure 6.8 Diagram of letdown line isolation and relief Valves

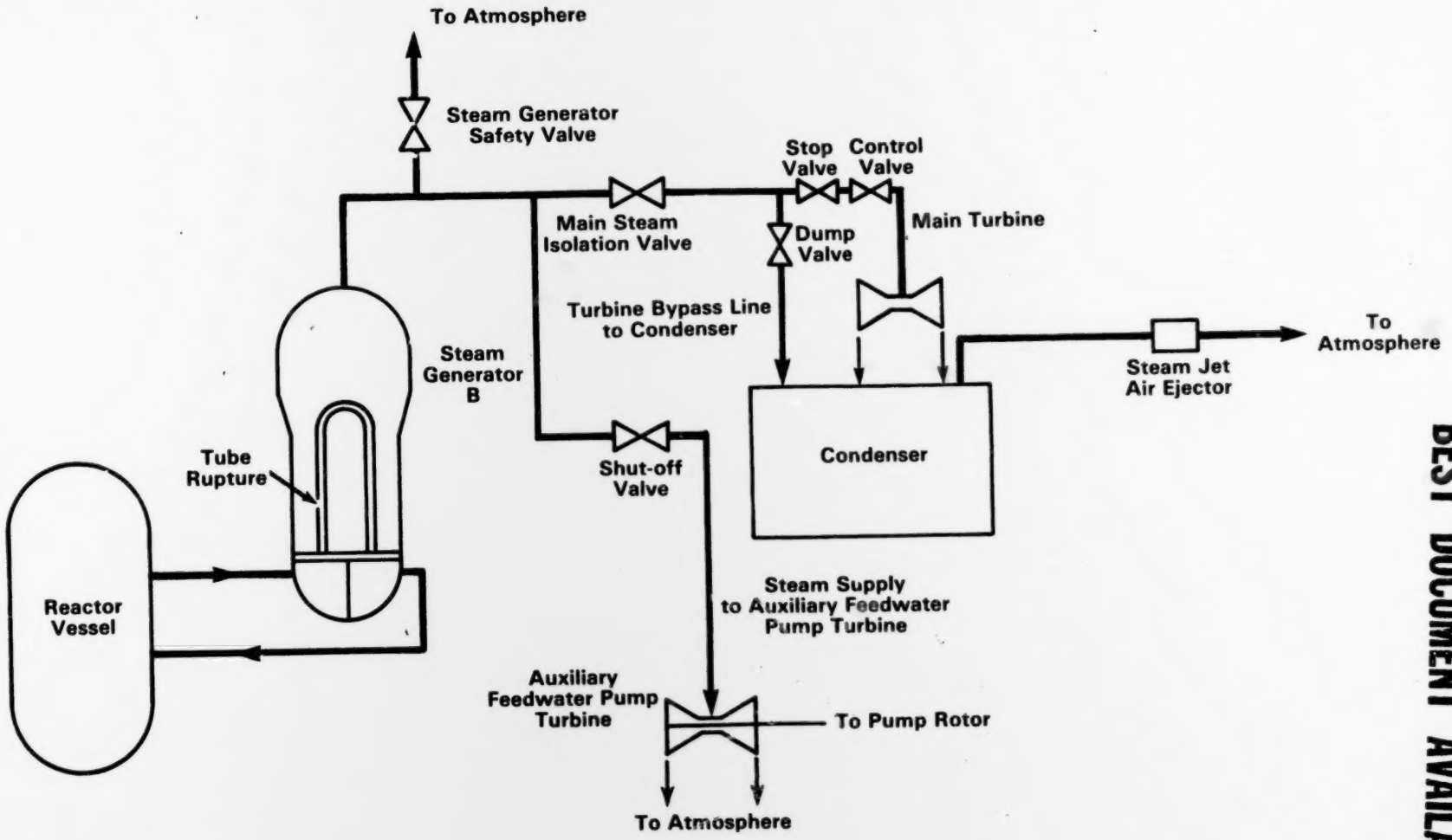
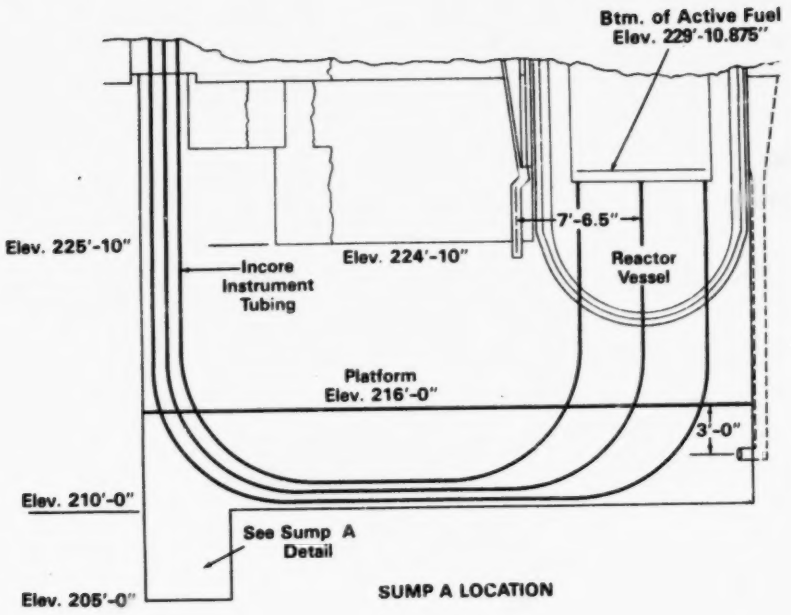


Figure 6.9 **Pathways for release of radionuclides to the environment from the Ginna steam generator tube rupture on January 25, 1982**

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE



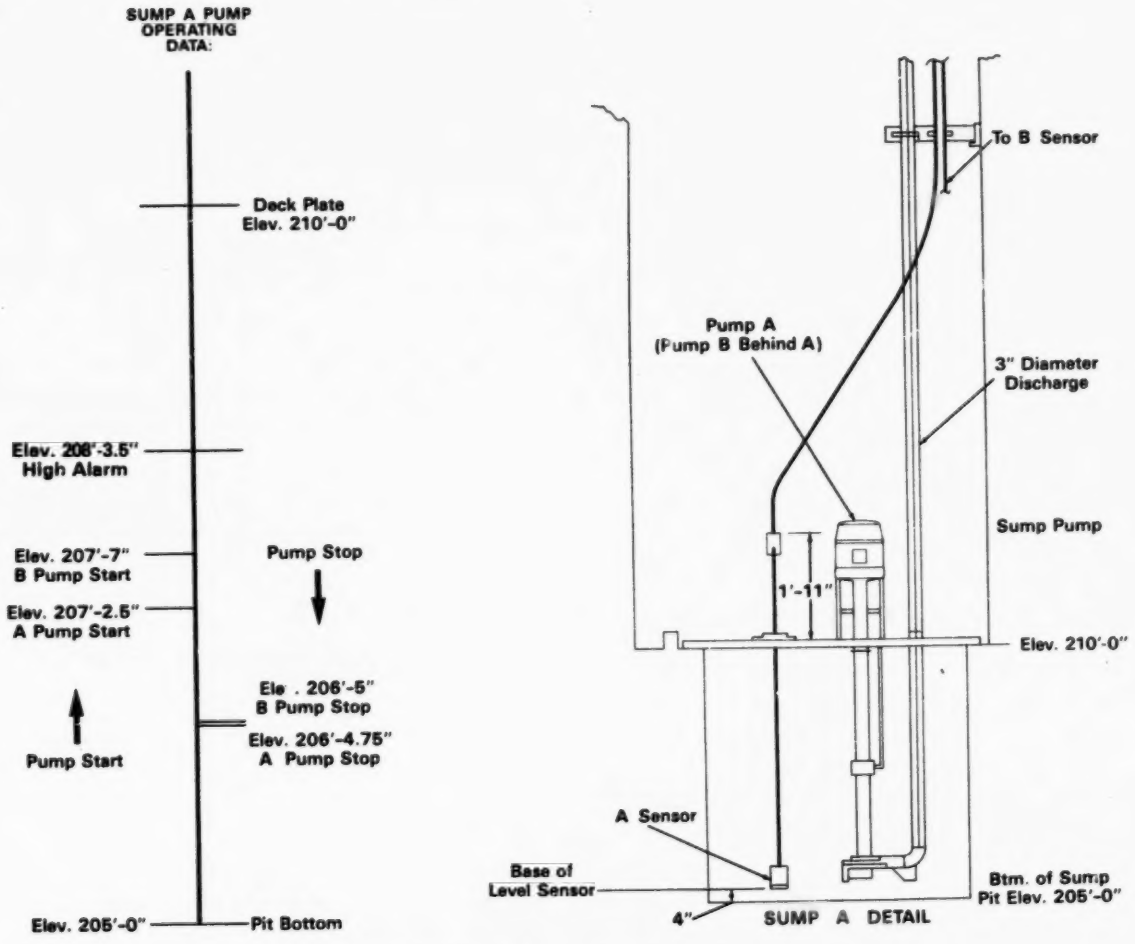


Figure 6.10 Containment Sump "A"

7.0 EMERGENCY PREPAREDNESS/NOTIFICATIONS

7.1 Background

Article 50.47 of 10 CFR 50 requires that all licensees have an emergency plan for onsite and offsite emergencies that provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Rochester Gas and Electric Corporation's plan was exercised and evaluated during a full scale emergency preparedness drill conducted January 21, 1982. An evaluation of the drill and RG&E's Emergency Plan will be issued by the NRC's Region I office in May 1982.

7.2 Notifications and Institutional Response

The incident led to implemention of the Ginna Radiological Emergency Plan and its associated procedures including notification of governmental agencies. Various organizations, including the licensee, state and local governments, NRC, and other Federal agencies responded to the event at Ginna.

The licensee had primary responsibility for resolving the conditions that existed at the plant. Prescribed initial notifications by the licensee to the State, local counties, and NRC were completed very early in the event, and interactons throughout the event were maintained among all the participants.

The Nuclear Regulatory Commission, using the resources of the Senior Resident Inspector, the Region I Base and Site Teams, and the Headquarters Executive and Analytical Teams, monitored the licensee's actions in response to the event to assure that these actions were correct and appropriate.

The State of New York and Wayne and Monroe Counties were promptly notified by the licensee. They responded by activating their Emergency Operations Centers and sending representatives to the site. Monroe County also fielded offsite

radiological monitoring teams and reported results back to the Emergency Operatins Center throughout the day. Twice during the first day of the event, the Governor of New York was briefed by the NRC Chairman on the status of the event.

The Federal Emergency Management Agency (FEMA) was notified of the event by NRC. FEMA then coordinated the Federal agency nontechnical response, both from their Headquarters and from their Region II facility in New York City. Agencies contacted by FEMA were: the U.S. Department of Agriculature, the Department of Energy, the Coast Guard, the Department of Housing and Urban Development, the Department of Transportation, the National Oceanic an Atmospheric Administration, Department of Health and Human Services, and the Department of Defense. Each of the agencies notified was prepared to respond in accordance with the responsibilities defined in the National Radiological Emergency Prepared/Response Plan.

7.3 Evaluation

The staff has reviewed the emergency preparedness items and findings regarding the steam generator tube rupture at the R. E. Ginna Nuclear Power Plant on January 25, 1982. The major documents used in this review included the incident evaluation, (Ref. 7.1) dated April 12, 1982, submitted by the licensee, and the NRC report, NUREG-0909, (Ref. 7.2) dated April 1982.

The staff found that no new deficiencies were indicated as a result of the indicent that were not previously identified in the Ginna Emergency Preparedness Evaluation Report (EPER) dated March 1982. In fact, the incident reinforces certain previous findings:

1. The plan states that the evacuation route will be determined by the emergency coordinator based on wind direction at the time of the accident. The licensee should discuss the means that will be used to transport people to the offsite assembly location(s), other then the Brookwood Science Information Center and alternative routes that could be used for various wind direction or in case of inclement weather.

2. The licensee should establish Emergency Action Levels (EALs) for each initiating condition specified in Appendix 1 to NUREG-0654 (Ref. 7.3). The EALs should be ovservables (e.g., instrument readings, equipment status indications, alarm annunciators) which are both necessary and sufficient to explicitly and uniquely characterized each initiating condition.

3. The licensee should detail the shift staffing requirements for emergencies.

4. The licensee should provide for centralized reporting of field monitoring data.

7.4 Conclusion

These deficiencies will require correction consistent with the schedule set forth in the forthcoming Emergency Preparedness Appraisal Report to be issued in May by Region I. From an emergency preparedness standpoint, the staff considers that plant restart and operation are acceptable.

7.5 References

7.1 Incident Evaluation, Ginna Steam Generator Tube Failure Incident, January 25, 1982, R. E. Ginna Nuclear Power Plant, Docket No. 50-244, April 12, 1982.

7.2 NUREG-0909, NRC Report on the January 25, 1982 Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant, April 1982.

7.3 NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, November 1980.

8.0 RADIOLOGICAL ASSESSMENT

During the tube rupture incident at Ginna, radioactive primary coolant leaked into the B-steam generator. Some of the contaminated secondary coolant was then released to the environment. A description of the releases and the follow-up activities is presented in chapter 5 of NUREG-0909 (ref 8.1) and Chapter 7 of the licensee's "Incident Evaluation (ref 8.2)." A discussion of the releases and the monitoring, surveying, and sampling activities after the incident as they relate to Ginna restart, and recommendations for licensee actions prior to and after restart, are presented in the following sections.

8.1 Recommendations for Mitigation of Radiological Consequences

During the January 25, 1982 incident at Ginna, the total amount of primary-to-secondary leakage and the total amount of water and steam released to the environment were larger than would normally be predicted, because of valve malfunctions and operator actions (see Chapters 3, 4, and 5 of NUREG-0909). A comparison with a previous safety evaluation report input on the radiological consequences of a steam generator tube rupture accident (SGTR) (ref 8.3) shows that the potential exists for doses exceeding Part 100 Guidelines from a design-basis SGTR accident. These doses would occur only if there were an unlikely, but not impossible, set of circumstances, namely: primary coolant with iodine concentration at the Westinghouse Standard Technical Specification coolant iodine concentration spiking limit of 60 μCi/g dose-equivalent I-131, maximum flow rate through a double-ended tube rupture, flow through the tube rupture prolonged for two or more hours, filling of the steam generator and steam line of the affected steam generator, releases through the affected steam generator's safety or atmospheric dump/relief valves as a two-phase mixture, and conservative atmospheric dispersion factors. The actual radiological consequences of the Ginna accident were not severe because the reactor coolant iodine concentration was very low, 0.057 μCi/g dose-equivalent I-131; and because the meteorologic conditions were far more favorable, with respect to offsite doses, than the conservative assumptions used in the prior analyses.

aspects of the Ginna accident were as severe as some of the above assumptions: the high initial rupture leak rate, the prolonged leak, the filling of the steam generator and part of the steam line, and the release of a two-phase mixture through the safety valve. Although a more serious event was avoided and the radioactivity releases were not excessive, the staff concluded that additional measures must be taken to prevent potential accidents in the future from having similarly large leakages and releases that could cause more severe radiological consequences.

The following discussion is provided to evaluate the general implications of events as they might affect the radiological consequences of potential incidents, and to provide a background for the suggested corrective measures. Two things that contributed to the prolonged primary-to-secondary leakage and the overfilling of the steam generator were (indirectly) the pressurizer PORV that stuck open, and the delayed decision to terminate safety injection (the staff notes that there were other legitimate concerns that required evaluation, that may also have contributed to this delay). Overfilling of the steam generator is undesirable with respect to releases of radioactivity for several reasons: as the water level rises above its normal value, the steam dryers flood, which permits higher moisture carryover (liquid droplets that may amount to a few percent of the total mass released) with the steam. When the steam generator is overfilled and the steam line is flooded to the MSIV, it is likely that most or all of the releases from the relief or safety valves will be as water or a two-phase mixture. This can cause a mass flow rate of contaminated secondary coolant to the environment that is higher than the design release rate, which is based on steam. (Two-phase flow through the relief or safety valves may contribute to valve degradation and possible failures to reseat. This can contribute to the radiological consequences by providing a prolonged pathway to the environment. The evaluation of both the pressurizer PORV and the safety valve function and their repair, is provided elsewhere in this SER (Sections 6.1 and 6.3.).

The release of a two-phase mixture also results in the transport to the environment of non-volatile radionuclides not expected to be present in a steam-only release, and a much higher concentration of iodine in the material released, because of the lack of liquid phase/gas phase partitioning.

The release of radioactive steam and water to the environment to relieve the pressure in the affected steam generator was worsened by the decision to close the block valve upstream of the affected B- steam generator atmospheric dump/relief valve, and the failure of the B-steam generator safety valve to reseat fully. The block valve closure forced the safety valve to open and close repeatedly to relieve pressure over a period of about two hours. This cycling, or the release of two-phase water/steam, may have contributed to the failure of the safety valve to reseat fully (see pages 3-18 and 3-19 of NUREG-0909 for further discussion). During a period of prolonged leakage into the steam generator, for which pressure relief may be repeatedly required, it may be better to use the steam generator atmospheric dump/relief valve on the affected steam generator, since that type of valve is better suited for cycling than safety valves.

The licensee has recommended several short-term procedural changes. A review of all these recommended changes appears elsewhere in this SER. The following specific changes or additions to Procedure E-1.4, "Steam Generator Tube Rupture," as proposed and annotated by the licensee, are designed to increase the likelihood that the unnecessary demand on the steam generator safety valves, prolonged primary-to-secondary leakage, and steam generator overfill will not occur:

"STEP 3.9.3 Change to read, 'put atmospheric steam dump <u>controller</u> in the manual closed position'.

This change will clarify that the controller is to be put into manual, but that the [block] valve itself need not be manually closed.

"Add NOTE After STEP 3.15.3 'Termination of SI with suspected voids in the upper RV head is allowed when natural circulation is verified. (Refer to O-8)'

This note serves to eliminate hesitancy in termination SI when the SI termination criteria are met and natural circulation is assured.

"Add STEP 3.20.3 'Block SI before the faulted S/G drops below 550 psig.'

This will prevent SI re-initiation due to low SG pressure.'"

The licensee is also recommending a long-term procedure change: "Add a section to the procedure to address operation with the faulted steam generator full of water."

However, the recommended procedure changes are, by themselves, insufficient evidence to the staff that potential steam generator tube rupture events will not result in offsite doses exceeding Part 100 guidelines. The licensee's FDSA (ref. 8.4) analysis of this accident did not take into account some of the factors noted above. Because of this, the concern about potentially high doses, and the incomplete evaluation of the effects of changes to operator guidelines, the staff recommends that the licensee re-analyze the radiological consequences of an SGTR accident. The new analysis should, in particular, either analyze the effect of prolonged primary-to-secondary leakage and over-filling of the steam generator, or provide evidence that this will not occur. As an interim measure, to reduce the probability that a steam generator tube rupture in the future will not result in severe radiological consequences, the staff will require that the technical specifications for primary coolant iodine concentration be changed, prior to restart, as follows: 1) a limit on the maximum primary coolant activity during spiking of 12 μCi/g dose-equivalent I-131 (DE I-131), a limit which, if exceeded, requires the plant to be in Hot Standby within 6 hours, 2) a long-term, equilibirum primary coolant iodine concentration of 0.2 μCi/g DE I-131, which cannot be exceeded more than 7 days without placing the reactor in Hot Standby, 3) a limit on the total duration during which the equilibrium limit is exceeded of 800 hours per year, and 4) the sampling and reporting requirements specified in the Westinghouse Standby Technical Specifications for those times that the coolant iodine concentration exceeds or has a potential for exceeding the equilibrium limit. The staff proposes that, if there is a favorable review of the recommended licensee SGTR evalution, these technical specification limits may be replaced by the less stringent Westinghouse Standard Technical Specification (STS) limits for iodine

activity, retaining the surveillance requirements. The licensee has proposed to change their technical specifications to incorporate the key elements as outlined above. See the enclosed Technical Specification modification.

The staff notes that it took the operators 15 minutes to identify positively the steam generator with a tube rupture during the Ginna accident. With respect to radiological consequences, the staff concludes that this was not an excessive time. For design basis analyses, the staff typically assumes that 30 minutes are required for positive identification of the affected generator.

8.2 Releases from the Unaffected Steam Generator

It has been noted that the dumping of slightly contaminated steam from the unaffected A- steam generator amounted to an intentional release to the atmosphere. This is a necessary and normal response to a steam generator tube rupture when the condenser is not available; and, because there are a variety of reasons why it is impossible or undesirable to use the condenser following the accident, this is the case for which licensing accident evaluations are done. However, the condenser is likely to be available, and useful, after most accidents. It appears that, during the January 25, 1982, incident at Ginna, removing the condensers from service could have been more carefully evaluated, taking into account the alternatives and the effects of additional environmental releases (see p. 3-15 of NUREG-0909). Recommendations have been made elsewhere in this Report for procedure changes to use the condenser as a heat sink (in conjunction with the unaffected steam generator) to achieve cooldown following an SGTR, in preference to the atmospheric dump valve. During the Ginna incident, the licensee did not sample the A-steam generator water prior to the first release from the A-atmospheric dump valve.

8.3 Survey Teams

In Section 7.4 of the licensee's Incident Evaluation Report and Section 5.7.5 of NUREG-0909 the actions and findings of the licensee's survey teams are discussed.

During the event the licensee dispatched 2 onsite and 3 offsite survey teams to record direct radiation exposure data and to collect environmental samples (e.g. air, water, and snow). Each team was equipped with Geiger-Mueller and scintillation detection equipment. Each team was assigned a particular route and conducted at least 2 surveys of each route during and subsequent to the releases. The surveys were conducted primarily in the quadrant SE of the release point to a distance of 4 miles.

The highest exposure rate measurement made in the course of the surveys, 3 mr/hr, was obtained at the site fence, approximately 130 meters southeast of the release point, as the team passed under a radioactive steam cloud. All other measurements onsite were lower by a factor of 2 or greater. Beyond the plant boundary all radiation levels were at background levels with the exception of one measurement of 1.2 mr/hr near the plant entrance.

These data were used by the NRC staff and the licensee to evaluate possible exposure to the maximum-exposed individual offsite. The NRC staff considers licensee actions in this area to be consistent with good health physics practice.

8.4 Sampling

In Section 7.5 of the licensee's Incident Evaluation Report and in Sections 5.7.2 through 5.7.4 of NUREG-0909 the findings of the licensees environmental sampling program during the event are discussed.

8.4.1 Air Sampling

The licensee's fixed air sampling stations were operating througout the event. Survey teams dispatched by the licensee shortly after the beginning of the event also collected airborne contamination samples with portable air sampling equipment. Three sampling locations exhibited iodine concentrations above background. The samples were collected downwind from the plant.

On the day of the event, instantaneous iodine concentrations higher than the annual average permitted by 10 CFR Part 20 for unrestricted areas were measured

at one onsite plant location. However, within 4 days of the event iodine concentrations had decreased to less than the detection limit of the counting equipment.

At 2 offsite locations the measured radioiodine concentrations were less than 25% of the maximum permissable air concentrations for unrestricted areas as specified in 10 CFR Part 20.

Because the iodine concentrations remained above background for several days after the releases, the licensee concluded that volatile radioiodines deposited on buildings near the release point continued to evolve and be carried downwind.

The NRC staff considers that the licensee's conclusions are consistent with the data, and that licensee actions in this area during the event were consistent with good health physics practices.

8.4.2 Snow Sampling

During the event snow was falling at a rate of about 1/4 inch per hour in the vicinity of Ginna. The licensee collected more than 100 snow samples from the ground, from vehicles, and from buildings.

Because of the wide variability in area, depth, density of the snow samples collected, and possible cross contamination of samples, measured concentrations of radioactive materials in snow could not be used to determine deposition quantitatively. However, a comparison of the relative concentrations for snow collected onsite and offsite indicates that a major portion of radioactive materials was deposited within the site boundary. The samples further indicated that a significant proportion of the iodine available for release from the B-steam generator was deposited in the snow onsite.

The NRC staff considers the licensee's conclusion about the relative depositon of radioactive materials to be consistent with the data. However, the NRC staff has concluded that if the licensee survey teams had established and implemented a uniform snow sampling procedure, an accurate assessment of the deposition of radioactive material could have been made.

Therefore, the staff recommends that the licensee develop a specific procedure for the uniform collection of snow samples, under snow conditions, during other than normal atmospheric releases of radioactive materials.

8.4.3 Water Samples

Onsite tap water samples and offsite samples at the Ontario Water Works were taken by the licensee. None of the analyses indicated radionuclide concentrations above the minimum detection capability of the instruments used.

The NRC staff considers licensee actions in this area to be consistent with good health physics practices.

8.5 TLD Measurements

The licensee had placed thermolumimescent dosimeters (TLDs) at 3 offsite locations including 11 at the site boundary and at 7 on site locations. Nine additional TLD's were placed offsite by survey teams immediately following the event. Additionally, the NRC had 27 TLD's offsite and the State of New York had 2 TLD's onsite.

With the exception of the two TLD's onsite that were situated approximately 0.2 mile downwind SE of the release point, no TLD measurement indicated an exposure significantly above background The 2 TLD's that recorded significant exposures (21.7 millirems as measured by RG&E and 9.4 millirems as measured by New York State) were located at the approximate centerline of the predicted plume. Most of these TLD exposures probably came from radioactivity materials deposited on the ground and nearby surfaces rather than from the plume itself.

These data were used by the NRC staff and the licensee to evaluate possible exposures to the maximum-exposed individual onsite. The NRC staff considers licensee actions in this area to be consistent with good health physics practices.

8.6 Estimated Offsite Doses

In Section 7.7 of the licensee's Incident Evaluation Report and in section 5.8 of NUREG-0909 the offsite population and maximum-exposed individual doses are discussed. External exposure, inhalation, and ingestion pathways were considered.

For plume exposure the licensee investigated the maximum individual doses from 2 sources of radiation: inhalation of radionuclides and external exposure to radiation. The licensee concluded that the maximum-exposed individual could have received a thyroid dose of 2 millirems offsite and a whole body dose of 0.07 millirem. The NRC staff has estimated that the maximum-exposed individual could have received a thyroid dose of less than 5 millirems offsite and a whole body dose of 0.5 millirem. The difference in the whole body doses may be attributed to the NRC staff's higher estimated source terms (Table 5.4 of NUREG-0909 and Tables 7.2-4 and 7.2-5 of the licensee's report).

For population doses the licensee estimated that the maximum whole body population dose within 40 miles of the plant is 0.2 person rem. The NRC staff has estimated that for the population within a 50 mile radius of the plant, the whole body dose is less than 0.1 person-rem.

Additionally, the licensee considered potential ingestion pathways, such as fish and drinking water consumption, due to runoff of melted snow into Deer Creek and the lake. The licensee concluded that the maximum-exposed individual would receive about 0.6 millirem and the maximum population dose would be 1.3 millirems. However, the licensee feels that these doses overestimate the actual doses because a large fraction of the deposited radioactivity in snow was plowed up and stored in the Radwaste bunker to allow radioactive decay prior to entering unrestricted water bodies. The staff has made no comparable analysis because of the lack of radionuclide deposition data.

Finally, the licensee compared predicted dose rates based on estimated radionuclide releases with actual measured dose rates near plant buildings. The licensee has determined that the actual dose rates were lower than the predicted

BEST DOCUMENT AVAILABLE

dose rates. The NRC did not perform a comparable analysis but considers the licensee's findings to be consistent with the data.

Based on the foregoing discussion the NRC staff has concluded that the licensee evaluation of offsite doses are consistent with that of the NRC staff.

8.7 Recommendations Regarding Ventilation Intake During Steam Generator Tube Rupture Releases

During the January 25, 1982 incident at Ginna, air contaminated by steam and/or water droplets released from the affected steam generator safety valve was pulled into the auxiliary building through the ventilation intake. (This is discussed further in pages 7.2-4 and 7.2-5 of the licensee's "Incident Evaluation".) Although relocation of the intake may be unrealistic, the staff recommends that the licensee consider a procedural change calling for closure of the auxiliary building's (and perhaps other buildings') ventilation intake ports, or turning off some of the intake fans, while a steam generator with a tube rupture has open safety or relief valves. The evaluation of this change should consider potential doses from the safety/relief valve source, potential doses resulting from disturbing normal ventilation flow paths for a short time, and potential short-term reductions in the cooling of safety-grade or safety-related equipment rooms. (The staff notes that the Ginna FDSAR states that essential equipment in the auxiliary building is supported by separate cooling and ventilation systems.)

8.8 Summary of Recommendations

In the previous sections, the staff has recommended several changes to mitigate radiological consequences from an SGTR at Ginna. In summary, they are: to adopt new technical specifications for reactor coolant iodine activity concentration and surveillance requirements providing for lower limits to make procedural changes to reduce the chances of unnecessary safety valve use, prolonged primary-to-secondary leakage, and steam generator overfilling; and to consider procedural changes to prevent or lessen ventilation intake of contaminated air during accidental releases.

Also, the NRC staff has evaluated the licensee's environmental monitoring program during the event and finds that the licensee's actions were, in general, consistent with good health physics practices and that the licensee's interpretation of data and conclusions are consistent with those of the NRC staff. However, the staff does recommend that the licensee develop a specific procedure for the uniform collection of snow samples during other than normal atmospheric releases of radioactive materials for inclusion in the final emergency response plan. Restart of the reactor should not be delayed for the development of this procedure.

8.9 References

8.1 NUREG-0909, NRC Report on the January 25, 1982 Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant, April, 1982.

8.2 Incident Evaluation, Ginna Steam Generator Tube Failure Incident, January 25, 1982, R.E. Ginna Nuclear Power Plant. Docket No. 50-244, April 12, 1982.

8.3 W. E. Kreger, NRC, to G. C. Lainas, NRC, Systematic Evaluate Program Evaluation of a Steam Generator Tube Rupture Accident at Ginna, Docket 50-244, June 25, 1981.

8.4 Rochester Gas and Electric Corporation Robert Emmett Ginna Nuclear Power Plant Unit No. 1, Final Facility Description and Safety Analysis Report, Vols 1-3, Docket 50-244, March, 1969.

8.5 NUREG-0800, Standard Review Plan, July 1981.

8.6 J. E. Maier, RE&E, letter to D. M. Crutchfield, NRC, Systematic Evaluation Program Integrated Assessment, Docket 50-244, Nov. 4, 1981.

9.0 COMMITMENTS

Rochester Gas and Electric Corporation was committed to the following short term requirements to be imlemented prior restart:

1. Perform a check of control board light bulbs each shift. (Section 4.2.15)

2. Relabel the pressurizer PORV and block valve switches to describe switch operation. (Section 4.2.6)

3. Change Procedure E-1.4 to provide guidance on bubble formation and the actions to be taken. (Section 4.2.2 and 4.2.6)

4. Revise E-1.4 to include guidance to the operator on the rate of RCS depressurization when the pressurizer PORV is opened. (Section 4.2.6)

Rocherster Gas and Electric Corp. was also committed to the following long term items:

1. Modify the 1C safety injection pump logic to establish a fixed loading sequence and to provide a lockout feature to prevent automatic transfer of a fault at the load to the redundant bus. (Section 6.7)

2. Within six months, reanalyze the radiological consequences of a steam generator tube rupture. The analysis should include the effect of overfilling the steam generator or evidence should be provided that overfilling will not occur. (Section 8.1)

3. Revise the setpoints and surveillance requirements for the effluent monitoring system. (Section 6.5)

4. Prior to December 1, 1982, develop procedures for snow sampling. (Section 8.4.2)

5. Within six months, consider procedure changes to reduce or prevent ventilation intake of contaminated air during unplanned releases. (Section 8.7)

6. Within six months, review the requirement for a safety injection signal to be present for automatic transfer of safety injection pump suction from the boric acid storage tanks to the refueling water storage tank. (Section 4.2.3)

7. Within six months perform a detailed thermal-hydraulic analysis of system behavior during the incident to verify phenomena, including void formation. (Section 3.3)

8. Within six months, study the RCP trip criteria with the purpose of finding a method to keep the RCPs running during a steam generator tube rupture. (Section 4.2.1)

9. Within six months, study the RCP restart criteria to ensure that proper criteria are employed. (Section 4.2.1)

10. Within six months, review plant procedures to provide any additional guidance required for operator actions to be taken in response to real or suspected reactor vessel upper head voiding. (Sections 3.3 and 4.2.2)

11. Within six months, provide procedures for cooldown following a steam generator tube rupture. (Section 4.2.11)

12. Within six months, provide procedures to cover a steam generator tube rupture with a failed open steam generator safety valve. (Section 4.2.12)

13. Within six months, review the time response of simulators used for operator training of steam generator tube ruptures and implement any actions necessary to identify differences between the simulator and Ginna. (Section 4.2.16)

14. Confirm by test that the modified letdown system isolation functions properly and submit, within six months, a detailed design description. (Section 6.4)

15. Confirm by test that the wide range pressurizer pressure transmitter functions properly and submit, within six months, a detailed design description. (Section 6.8)

16. Perform fiber optic inspections during the intermediate outage of the tubes in Row 45 of the B-steam generator hot leg. (Section 5.5.8.4)

17. Submit, within six months, a detailed design description of the Loose Parts Monitoring System. (Section 5.5.6)

18. Within six months, review and identify potential transients and accident scenarios that could provide relatively stagnant flow conditions in a coolant loop, and examine the effect of the operator taking actions which would draw the cold water into the vessel. For these scenarios, review and modify procedures and train operators as necessary to prevent or minimize the flow of cold water into the vessel. (Section 3.5)

19. In the long term, include an evaluation of the scenarios identified above in the overall resolution of the pressurized thermal shock issue. Modify equipment, procedures and operator training in accordance with the resolution of that issue. (Section 3.5)

10.0 SUMMARY OF FINDINGS

With the exception of the information to be provided at a later date as described in Section 9.0, which will be evaluated in a supplement to this report, the NRC staff has completed its review of the Ginna steam generator tube rupture event. This review included the licensee's submittals, reports from the NRC consultants, Brookhaven National Laboratory and Franklin Research Center, and the staff's independent analyses. The NRC staff concludes that restart of the R.E. Ginna Nuclear Power Plant is acceptable based on the following conclusions:

1. Investigations of the mechanisms that led to the steam generator tube rupture on January 25, 1982 were conducted by Westinghouse and Battelle (Colombus) Laboratories for Rochester Gas and Electric and by Brookhaven National Laboratory and Franklin Research Center in conjunction with the NRC staff. It has been satisfactorily established that a large foreign object most probably initiated the damage in the B-steam generator that led to the tube rupture. The foreign object acted on tubes in the outer row of the steam generator causing sufficient degradation in these tubes to cause them to be removed form service by plugging both ends. The foreign object continued to act on the plugged tubes until they collapsed and eventually severed at the lower end of the tube. These severed tubes were then free to act on adjacent tubes; eventually causing them to be plugged and possibly to sever. This domino affect repeated itself until one tube experienced wear over a long enough length that it burst rather than developing a small leak or pluggable indication.

   The staff has reviewed Rochester Gas and Electric Corporation's repair and inspection program. Post rupture examination revealed that severe damage had occurred to 26 tubes in the periphery of B-steam generator. The damage to these tubes was felt by the licensee to be of such extent as to warrant removal of those tubes to prevent further damage to sound tubes. The licensee's inspections indicate that all foreign objects have been

removed from the steam generators. These repairs and inspections have been reviewed and the staff concludes that the integrity requirements of the active tubes are satisfied by the existing inspection and repair program for steam generator tubing. Additionally, Rochesters Gas and Electric Corporation plans to shutdown the Ginna plant after 120 days for followup inspections to assure that the corrective actions taken to preclude further peripheral tube degradation have been successful.

2. The pressurizer power operated relief valve malfunctioned after opening and closing successfully three times. When trying to close the valve after the fourth time it was opened, the PORV started to close then returned to the full open position. Rochester Gas and Electric Corporation has performed extensive tests on the PORV and on the valves that control the air that operates the PORV. They have determined that an alteration performed on one of the air control valves in 1979 was not in accordance with the manufacturers installation and maintenance instructions. The air control valve and its associated piping has now been modified in accordance with the valve manufacturers recommendations to ensure proper operation of the PORV. The NRC staff concurs with the modification and concludes that future performance of the pressurizer PORV will be acceptable.

3. The staff's evaluation indicated that the operators' response and the written procedures used to mitigate the event were for the most part consistent with the predicted and accepted guidelines on which operator training and procedures were based. Some significant deviations from the procedures were consciously made by the operators after the consequences of those deviations were reviewed and approved by the Ginna Management. A review of these deviations by Rochester Gas and Electric Corporation has resulted in short term modifications to the procedures and a commitment to perform further analyses to determine if any long term modifications are necessary. The NRC staff concludes that based on the evaluation of the licensee's reponse to the event and the subsequent program for further improvements, adequate protection is provided for steam generator tube rupture events.

BEST DOCUMENT AVAILABL

4. The licensee and the NRC staff have performed independent analyses of the pressure and temperature transients imposed on the reactor vessel during the SGTR event. The staff has determined that during the most severe temperature decrease water was most probably flowing away from the reactor vessel towards the steam generator with the ruptured tube. This would indicate that the reactor vessel was never subject to an adverse temperature decrease.

   Furthermore, the staff has performed conservative fracture mechanics analyses that assume that the reactor vessel was subjected to temperature transient recorded by the faulted loops instruments. The staff's analyses show that even for this worse case, no cracks would initiate in the reactor vessel welds and therefore, pressurized thermal shock did not occur.

5. The NRC staff has concluded that the radiological consequences of this incident were below the levels calculated in the Final Design Safety Analysis and reanalyzed as a part of the Systematic Evaluation Program. However, the current analysis of the SGTR event does not consider certain assumptions that existed during this event. The staff concludes that Rochester Gas and Electric Corporation should reduce the technical specification limit for reactor coolant iodine concentrations to ensure that releases from a potential future event are kept well within acceptable guidelines.

   Based on the above specific conclusions and the NRC staff's overall review of the events surrounding the steam generator tube rupture, the staff concludes that there is reasonable assurance that the health and safety of the public will not be endangered by the proposed operation of the R. E. Ginna Nuclear Plant.

11.0 ENVIRONMENTAL CONSIDERATION

We have determined that the license amendment involving the Technical Specification change discussed in Section 8.1 of this report and the license condition imposed, as listed in Section 9.0 does not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. Having made this determination, we have further concluded that the amendment involves an action which is insignificant from the standpoint of environmental impact and, pursuant to 10 CFR §51.5(d)(4), that an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of this amendment.

12.0 CONCLUSION

We have concluded, based on the consideration discussed in this report, that: (1) because the license amendment involving the technical specification change discussed in Section 8.1 of this report and the license condition imposed, as listed in Section 9.0 does not involve a significant increase in the probability or consequences of accidents previously considered and does not involve a significant decrease in a safety margin, the amendment does not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

13.0 ACKNOWLEDGEMENTS

The follow NRC personnel have contributed to this evaluation:

J. Lyons
R. Caruso
C. Tropf
J. Page
S. Bryan
E. Marinos
J. Rajan
J. Lezevnick
M. Wanglar
J. Lee
M. Tokar
J. Nehemais
P. Easley
A. Gill
K. Parczewski
J. Joyce
N. Fioravante
K. Perkins
K. Wichman
E. Murphy
B. Martin
C. Cheng
R. Priebe
E. Throm
R. Kecker
R. Eckenrode
C. Costantino
Y. Hsii

APPENDIX A

BEST DOCUMENT AVAILABLE

BNL-NUREG-31283
Informal
FIN A-3400

Investigation of Failed Tubes from "B" Steam Generator of the R. E. Ginna Nuclear Power Plant *

Carl J. Czajkowski

May 1982

Brookhaven National Laboratory
Department of Nuclear Energy
Corrosion Science Group
Upton, New York 11973

*Research carried out under the auspices of the U. S. Nuclear Regulatory Commission

BEST DOCUMENT AVAILABLE

TABLE OF CONTENTS

		Pages
	List of Tables	ii
	List of Figures	iii
	Abstract	viii
1.0	Background	1
2.0	Investigation	2
	2.1 Photography	3
	2.1.1 Abraded Areas	3
	2.1.2 Impacted Areas	3
	2.2 Dye Penetrant Examination	4
	2.3 Scanning Electron Microscopy Examination	5
	2.4 Energy Dispersive Spectroscopy	6
	2.5 Optical Microscopy	7
3.0	Discussion and Conclusions	8
4.0	Acknowledgements	9

LIST OF TABLES

Page

TABLE 1 Total Dose 40 mR @ 1' Distance..... 10

BEST DOCUMENT AVAILABLE

LIST OF FIGURES

Page

Figure 1 Photograph of "as received" 10" long sections of damaged tubes from Rochester Gas and Electric's (RG&E) GINNA Station..... 11

Figure 2 Photograph of specimen #7 from tube R43-C55 (GINNA) depicting through wall wear from a probable abrasion mechanism..... 12

Figure 3 Photograph of specimen #3 from tube R43-C56 and #7C from tube R42-C55 (GINNA)..... 13

Figure 4 Photograph depicting areas of apparent abrasion on specimen #6 of tube R44-C54 (GINNA)..... 14

Figure 5 Photograph depicting severely abraded areas "through wall" on tube R43-C56 (GINNA)..... 15

Figure 6 Photograph of severely abraded area and "through wall" thinning on specimen #1 of tube R43-C54 (GINNA)..... 16

Figure 7 Diagram of Number 4 Wedge Area - Steam Generator "B" Hot Leg Side..... 17

Figure 8 Photograph of collapsed area in tube R44-C57 (GINNA).. 18

Figure 9 Photograph of apparently rubbed area in tube R8-C92... 19

Figure 10 Photograph of abraded area in tube R10-C91 (GINNA).... 20

BEST DOCUMENT AVAILABLE

LIST OF FIGURES (cont'd)

Page

Figure 11 Layout of Hot Leg Side of "B" Steam Generator depicting Wedge Areas..... 21

Figure 12 Photograph of two pieces of tube R44-C54 portraying considerable deformation..... 22

Figure 13 Photograph of severely deformed area in tube R44-C55 (GINNA)..... 23

Figure 14 Photograph of probable "miscut" of Electric Discharge Machining (EDM) apparatus on tube R43-C59 (GINNA)..... 24

Figure 15 Photograph of "fish mouth" crack in tube R42-C55 (GINNA)..... 25

Figure 16 Overlay Depicting the Sectioning of R42-C55 (GINNA)... 26

Figure 17 SEM photo of knife edge on R42-C55. Typical of "bulging" prior to ductile overload specimen #1..... 27

Figure 18 SEM photo of knife edge on R42-C55. Elongation of dimples less pronounced. Specimen #2..... 27

Figure 19 SEM photo of knife edge on R42-C55. Higher magnification. Specimen #2..... 27

Figure 20 SEM photo of knife edge on R42-C55. Specimen #3..... 27

Figure 21 SEM photo of knife edge on R42-C55 depicting impact after break. Specimen #3..... 28

Figure 22 SEM photo of knife edge on R42-C55. Specimen #4..... 28

BEST DOCUMENT AVAILABLE

LIST OF FIGURES (cont'd)

Page

Figure 23 SEM photo of transition of knife edge on R42-C55. Specimen #4..... 28

Figure 24 SEM photo of transition of knife edge on R42-C55. Specimen #4..... 28

Figure 25 SEM photo of "chevron" marks (indicative of fatigue failure) on Tube R44-C56 (top) near tube support plate 29

Figure 26 SEM photo of probable initiation site for cyclic fatigue failure of tube R44-C56..... 29

Figure 27 Higher magnification SEM photo of "initiation site" - Tube R44-C56..... 29

Figure 28 SEM photo of inside surface of tube R43-C59 depicting area of possible deep etching..... 30

Figure 29 Higher magnification SEM photo of inside surface of tube R43-C59..... 30

Figure 30 SEM photo of outside surface of abraded tube R11-C91.. 30

Figure 31 SEM photo of particle on inside surface of tube R8-C92 near rubbed area..... 31

Figure 31a EDS scan of particle on inside surface of tube R8-C92 for constituents..... 31

Figure 32 SEM photo of inside surface of tube R8-C92 depicting area of wall collapse..... 32

BEST DOCUMENT AVAILABLE

LIST OF FIGURES (cont'd)

Page

Figure 32a EDS scan of inside surface of tube R8-C92 near collapse for constituents..... 32

Figure 33 SEM photo of inside surface of tube R8-C92 depicting "etched" structure..... 32

Figure 34 Imbedded particle found on outside surface (O.D.) of R43-59..... 33

Figure 34a EDS scan of imbedded particle found on R43-59..... 33

Figure 35 Higher magnification SEM photo of "imbedded" particle. 33

Figure 36 SEM photo of another "smear" of iron (prior EDS scan is typical) found on outside surface of R43-59..... 33

Figure 37 Optical photomicrograph of cross section of "fishmouth" fracture (tube R42-C55) also shown is area of section relative to fracture. (Note: photomicrograph is optically reversed.)..... 34

Figure 38 Optical photo depicting area of cold work on tube R8-C92..... 35

Figure 39 Optical photo displaying area of cold work on tube R10-C91..... 35

Figure 40 Low magnification photo of cold work on collapsed tube R44-C57..... 35

BEST DOCUMENT AVAILABLE

LIST OF FIGURES (cont'd)

Page

Figure 41 Higher magnification photo of cold work on tube R44-C57 (Area B)..... 35

Figure 42 Cross sectional photomicrograph showing extent of damage endured by tube R44-C57. Also shown is area of section taken relative to collapse area..... 36

Figure 43 Optical cross section of segments from tube R8-C92 displaying extent of grain boundary etching..... 37

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

Abstract

An investigation was performed on various steam generator tubes from the R. E. Ginna nuclear power plant (Rochester Gas and Electric). These tubes were involved in the loss of coolant accident of January, 1982. The examination of the tubes included optical metallography, scanning electron microscopy, energy dispersive spectroscopy and liquid dye penetrant examination. The report concludes that the loss of coolant accident was the result of a purely mechanical mechanism caused by an adjacent severed tube rubbing the outer surface of tube R42-C55 until its cross section was insufficient to withstand the primary to secondary side pressure differential. The initial severing of the adjacent tubes is considered to have been caused by the impacting of a carbon steel foreign object(s) on the outer periphery tubes in the "B" steam generator.

BEST DOCUMENT AVAILABLE

1.0 Background

On the morning of January 25, 1982 while the R. E. Ginna nuclear plant was operating at 100% power (normal operating conditions) a series of alarms indicated a steam generator tube rupture. Various procedures were instituted in order to achieve a cold shutdown condition. Cold shutdown was finally achieved early January 26, 1982.

Visual and video inspections by the utility (Rochester Gas and Electric - RGE) determined that the tube at Row 42 - Column 55 (R42-C55) had developed a "fishmouth" type crack which had resulted in the loss of primary coolant. Additional inspections by RGE personnel determined that various surrounding tubes had been severely degraded and a failure analysis program was instituted by the utility.

Several tubes and fragmented tube sections were pulled, and sent to Westinghouse Corporation for analysis. Additionally, two tubes; R45-C54 and R45-C47 were sent to Battelle Columbus Laboratory for evaluation.

On April 6, 1982 a meeting was convened with the utility, representatives of the United States Nuclear Regulatory Commission (USNRC), a representative from the Franklin Institute and two representatives from Brookhaven National Laboratory (BNL) to discuss preliminary findings of the ongoing failure analyses. The presentation of Westinghouse results suggested a purely mechanical type failure caused by an adjacent tube rubbing the outer surface of R42-C55 until the cross section of the tube (R42-C55) was worn to a thickness insufficient to withstand the pressure differential between the primary and secondary pressure boundary. This cross sectional reduction caused the tube to fail by a ductile overload mechanism and manifested itself as a "fishmouth" type fissure. This end result was postulated by the utility to have been caused by the synergistic progression of foreign objects (apparently carbon steel plates) impacting the outer periphery of previously plugged tubes severely enough to break the tube(s) at or near the tube sheet junction and that these tubes caused damage and wear to adjacent plugged tubes

through a whipping mechanism (caused by turbulent water flow) until tube R42-C55 was affected and finally burst.

Because of the potential safety ramifications of this incident, BNL was requested by the Materials Engineering Branch of the USNRC (W. S. Hazelton, Acting Chief) that BNL was to conduct an independent failure analysis of affected tubes in order to confirm the RGE hypothesis of the incident's cause. This request was made under the Technical Assistance Program, "Evaluation of Material Problems and Failures," FIN A-3400.

Pursuant to this request, various tubes and tube sections were sent to BNL for evaluation.

2.0 Investigation

The tubes sent to BNL consisted of tubes previously examined by Westinghouse R44-C54, R43-C54, R44-C55, R43-C55, R43-C56 and the lower half of the "fishmouth" fissure of tube R42-C55. Additionally, RGE sent sections of R43-C59, R44-C56, R44-C57, R11-C91, R8-C92, and R10-C91 directly to BNL for examination.

All specimens received were examined visually. The following examinations were performed on selected tubes for the failure evaluation:

1) Visual Inspection/Optical Metallography/Photography
2) Scanning Electron Microscopy (SEM)
3) Energy Dispersive Spectroscopy (EDS) of severely degraded outside surfaces
4) Liquid Dye Penetrant Examination of inside surfaces of various tube sections

After determining the size and radioactivity level of the specimens received [Table 1] close up photographs were taken of all significantly sized pieces for cataloging.

BEST DOCUMENT AVAILABLE

2.1 Photography

Figure 1 depicts six tube sections received by BNL. The figure gives a good cross section of the types of damage encountered by the steam generator tubing in service. NOTE: the light colored dot, on the specimens, indicates that portion of the tube facing the shell of the steam generator.

2.1.1 Abraded Areas

The photographs (Figures 2-6) portray areas of the various tubes which have been worn away by a probable abrasion mechanism. These tubes are on the inner rows of the steam generator (Figure 7) and the longitudinal wear patterns (with circumferential striations) are consistent with two tubes rubbing together for an extended period of time.

2.1.2 Impacted Areas

One of the tube sections received (R44-C57), had an area of full collapse in the area of the tube sheet junction (Figure 8). This tube is in the outer periphery of the tube bundle (Figure 7) and the concave portion of the collapse faces the shell of the steam generator. The next two photographs (Figures 9-10) show an impact and wear mechanism which occurred on tubes away from the area of the leak (#4 wedge area) in the #6 wedge area.(Fig. 11) The severest damage occurred on the tube where its circumference faced the steam generator shell. The wear patterns were consistent with the rubbing of one tube by another tube of appoximately 7/8" outside diameter.

Figure 12 depicts the severe impact damage which occurred on tube R44-C54. Again, it is evident that the most severe deformation occurred on the side of this outer periphery tube facing the shell.

Figure 13 is a photograph of a severed section from tube R44-C55. This tube displayed severe impact type damage and wall thinning.

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

Tube R43-C59 (Figure 14) displayed a chisel-like cut and an impacted area (not shown on photo). The impacted area was approximately 1/2" diameter and hemispherical in shape. It was later determined that the cut was caused by a "miscut" of an electric discharge machining device, which was used to cut the tube section free from the steam generator, and did not occur in service.

The bottom half of the "fishmouth" fissure (R42-C55) is displayed in Figure 15. Longitudinal wear scars (with circumferential striations) are quite evident in the photograph. These wear patterns are consistent with similar areas found on other inner steam generator tubes. There were no areas of impact evident on this tube.

2.2 Liquid Dye Penetrant Examination

Dye penetrant examination was performed on the inside surface of seven sections of tube. The tubes examined and the results of the test are listed below:

Tube I.D.	Test Result
R11-C91	No relevant indications
R42-C55 (Fishmouth)	No relevant indications
R10-C91	No relevant indications
R08-C92	No relevant indications
R44-C56	No relevant indications
R43-C59	No relevant indications
R44-C57	No relevant indications

The tests were performed at room temperature and used the following Spotcheck Brand components: Cleaner/Remover SKC-NF, Developer SKD-NF and Penetrant SKL-HF/SKL-S; all Formula B.

BEST DOCUMENT AVAILABLE

2.3 Scanning Electron Microscopy Examination

The "fishmouth" fissure on tube R42-C55 was sectioned (Figure 16) for both SEM and optical examinations. Figures 17-24 are typical SEM photographs of the face of the "knife edge" fissure starting near the center of the "fishmouth" and moving along its length to the crotch of the crack. It is clearly seen in Figures 17 and 18, that the mode of failure was a ductile overload mechanism. The normally circular dimples (if a uniaxial tensile test were performed) are somewhat elongated, which is evidence of a pipe bulge prior to break. The elongated dimpled structure of the fracture disappeared the farther away the "fishmouth" was scanned from the center of the fissure, as seen in Figures 19-22. An impacted area was noted in specimen #3 (Figure 21), which appeared to have occurred after the tube failed. This occurrance would be consistent with the postulation that loose objects were present in the steam generator at the time of failure. Figures 23 and 24 are SEM photographs of the transition zone (end of crack) in specimen #4. It is evident by the photographs, that the end of the crack also displayed ductile overload features with no evidence of fatigue contribution.

A section of tube R44-C56 was also examined by SEM. This tube had been collapsed and broken at the tube sheet and had also been severed by the tube support plate. The section viewed was the cross section of the tube, where it was severed just below the tube support plate. The majority of the fracture face was featureless and had a tamped appearance. One interesting feature was noted on the specimen, however, shown in Figures 25-27. Chevron marks were evident (Figure 25) on the surface of the fracture, which led to a cyclically fatigued area on the specimen (Figures 26 and 27). This type of structure would be consistent with a tube breaking by the tube sheet and then "whipping" about in a turbulent flow, causing a fatigue type failure of the tube by the upper tube support plate.

An examination of the inside surface of tube R43-C59 showed one area, which initially appeared as an intergranular type crack in the tube (Figures 28 and 29). The crack-like indication found on this tube was later

BEST DOCUMENT AVAILABLE

determined to be associated with a prior pickling process (see EDS section).

Figure 30 is an SEM photograph of a typically abraded and impacted section of tube R11-C91. Although some wear lines are evident, the section has no predominant distinguishing features.

2.4 Energy Dispersive Spectroscopy (EDS)

Prior to EDS viewing of specimens, they were decontaminated using the following sequence of steps:

1. Ultrasonically clean in "Microclean" for 1 hour;

2. water wash;

3. ultrasonically clean in Methanol for 15 minutes.

This sequence was accomplished twice prior to viewing the specimens.

This decontamination sequence had the effect of removing any loose particles from the specimens, and may have been responsible for displacing any evidence of impacting material on the majority of the scans.

Various EDS scans were performed on the outside surface of the impacted specimens of tubes, and on the inside surfaces of the impacted sections (adjacent to any breaks in the tube), in the hopes of obtaining information on the composition of the impacting object. Figures 31 and 32 are typical of the scans encountered on tube R8-C92 and are representative of the majority of scans taken.

Figure 33 is representative of the type of "etched" structure found on the inside surface of tube R8-C92. This structure was much more prevalent on this tube than the one area found on tube R43-C59. It was probably the result of pickling done on the tubes prior to their installation.

BEST DOCUMENT AVAILABLE

The last set of EDS scans (Figures 34, 35, and 36) display the constituents found on two smears on an impacted area on the outside surface of tube R43-C59. The scan (Figure 34a) is typical of that found on both of the smears and shows an extremely high peak of iron (Fe) relative to chromium and nickel. Since tube R43-C59 is an outer periphery tube, this finding appears to corroborate the hypothesis that the outer periphery tube damage occurred as a result of impact with a carbon steel foreign object.

2.5 Optical Microscopy

A cross sectional metallurgical mount was made of the number 1 area of the "fishmouth" fracture on tube R42-C55. It was etched with a 10% Bromine + Methanol etch for 20 seconds (Figure 37). There was no real evidence of cold work on this section, even though the wear patterns on the cross section are quite distinguishable. This type of wear would be consistent with a fretting corrosion mechanism, which would have reduced the tubes cross section by slow grinding over a long time period, coupled with oxidation of the freshly created surface.

Cold work was in evidence on cross sections of tubes R10-C91 and R8-C92 in small amounts and is depicted on Figures 38 and 39. The most significant areas of cold work were found on tube R44-C57 on a cross section of the collapsed area. Figures 40 and 41 give a good representation on the amount of repetitive cold work that this tube endured. Figure 42 is a full cross section of the tube displaying the amount of structural damage that the tube received prior to the plants shutdown. It is significant to note that cold work was primarily found on the outer (periphery) tubes, with the inner row tubes displaying a fretting corrosion microstructure.

Since a grain boundary "etching" was noticed during SEM examination, an optical mount was made of tube R8-C92. As can be seen on Figure 43, the extent of grain boundary etching is only a few grains deep (approximately .001") which is consistent with the suggestion that this attack was caused by

BEST DOCUMENT AVAILABLE

pickling prior to plant operations and deceptively appears significant only on severely degraded areas of the section.

3.0 Discussion and Conclusions

It is evident from this investigation, that all damage which occurred in the steam generator was caused by mechanical damage whether wear/abrasion or an impact mechanism resulting in ductile overload fatigue type failures or mechanical collapse. The fact that inner tubes displayed a fretting type wear with no significant areas of cold work, while outer periphery tubes displayed significant cold work, is consistent with the RGE hypothesis that damage occurred on the outer periphery tubes by impact with a foreign object(s). This theory is also substantiated by the discovery of iron smears on the outer surface of an outer periphery tube R43-C59.

The grain boundary "etching" was probably the result of an incomplete pickling operation and did not appear to have adversely affected the tubing or have contributed in any way to the "loss of primary coolant" incident.

It is, therefore, concluded that the final tube rupture (R42-C55) occurred as a result of the synergistic degradation of previously plugged steam generator tubes initially caused by impact and final severence of the outer periphery tubes by a foreign object(s).

BEST DOCUMENT AVAILABLE

4.0 Acknowledgement

The author acknowledges the help given him by the BNL Health Physics Group, specifically A. Lucas, R. Vogel and J. O'Connor. The invaluable help of R. Jones, K. Sutter, D. Becker, and L. Gerlach in decontamination and sectioning is gratefully appreciated. The author also wishes to thank R. Sabatini for the SEM/EDS work, P. Colsman for expediting the sample delivery, J. Langan and O. Betancourt for their typing skills, and Dr. J. R. Weeks for his continuing support and helpful discussions.

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

TABLE 1

PC #	Date	(Contact) Reading	Approximate Size	Comments
R43C59	4/8/82	300 mR/hr.	10"	
R44C56	"	200 mR	10"	
R11C91	"	150 mR	10"	
R44C57	"	200 mR	10"	
R8C92	"	150 mR	10"	
R10C91	"	200 mR	10"	
R43C54	"	40 mR	1"	
R44C54	"	40 mR	1"	
R44C55 #3	"	40 mR	2"/1"	
R44C55 #5	"	20 mR	3/4"	
R44C54 #2A	"	10 mR	1/2"	
R43C55 #7	"	80 mR	2"	
R42C55 #5	"	80 mR	1/4"	
R42C55 #4	"	130 mR	1/2"	
R42C55 #7C	"	80 mR	1"	
R42C55 #7	"	50 mR	1/2"	
R43C56 #3	"	40 mR	1"	
R43C55 #1	"	70 mR	3"	
R43C55 #3	"	40 mR	3/4"	
R44C55 #1	"	20 mR	1/2"	
R43C55 #5	"	50 mR	1"	
R44C54 #6	"	60 mR	1 1/2"	
R42C55 #1	"	40 mR	4" FM	
R42C55 #2	"	80 mR	1/2"	
R43C55 #2A	"	30 mR	1/2"	
R44C54 #4	"	30 mR	1"	
R43C54 #5	"	70 mR	2"	
R44C55	"	30 mR	4"	
R43C56 #1	"	90 mR	4"	
R43C54 #1	"	110 mR	4"	
R43C55 #2B	"	10 mR	1/4"	
R44C55 #2A	"	20 mR	2-1/4"	
R44C55 #2B	"	10 mR	1/4"	
R44C54 #2	"	30 mR	1 1/2"	
R43C56 #5	"	70 mR	2"	
R44C55 #7	"	30 mR	3/4"	

TOTAL DOSE 40 mR @ 1' DISTANCE

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

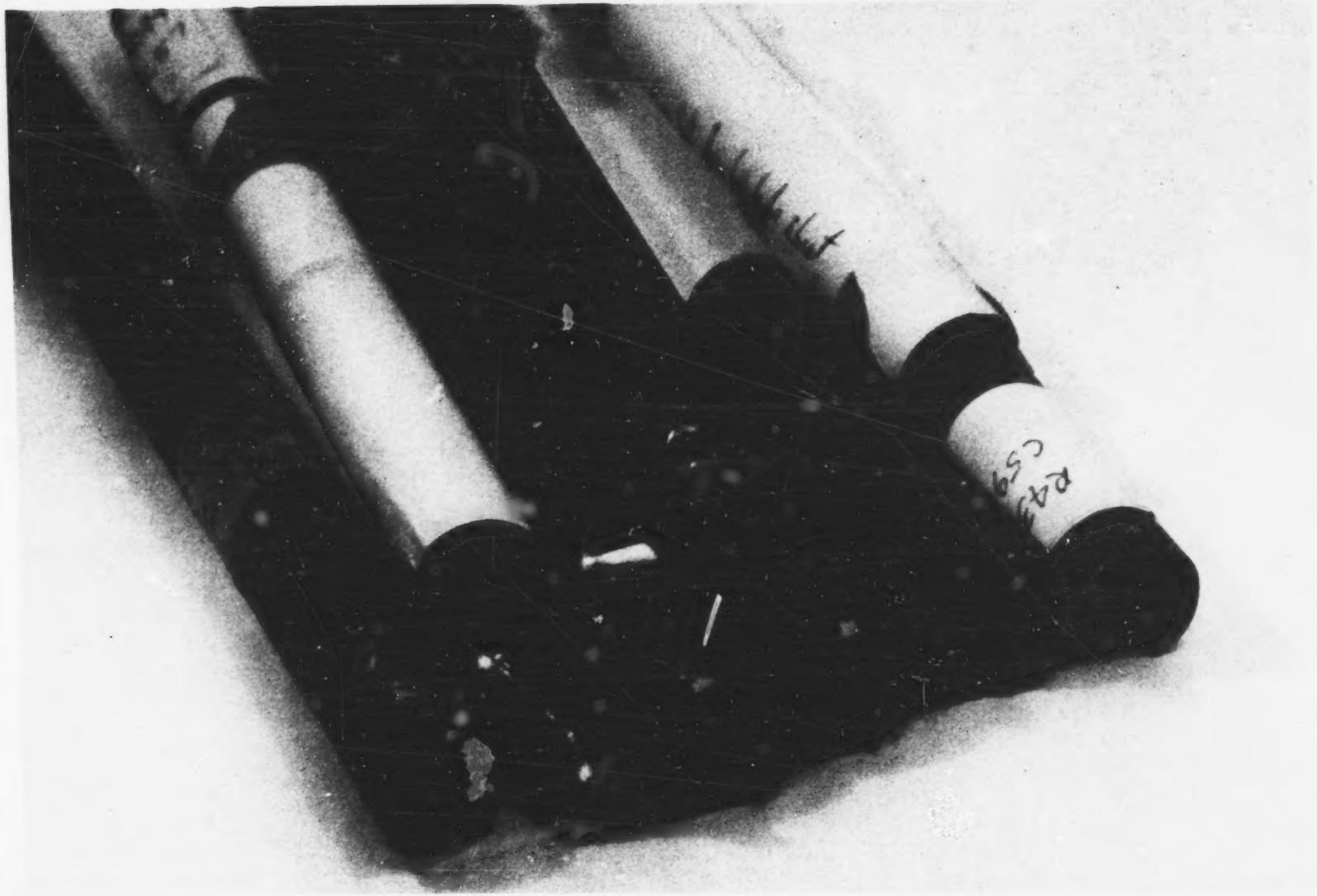


Figure 1. Photograph of "as received" ~10" long sections of damaged tubes from Rochester Gas and Electric's (RG&E) GINNA Station

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

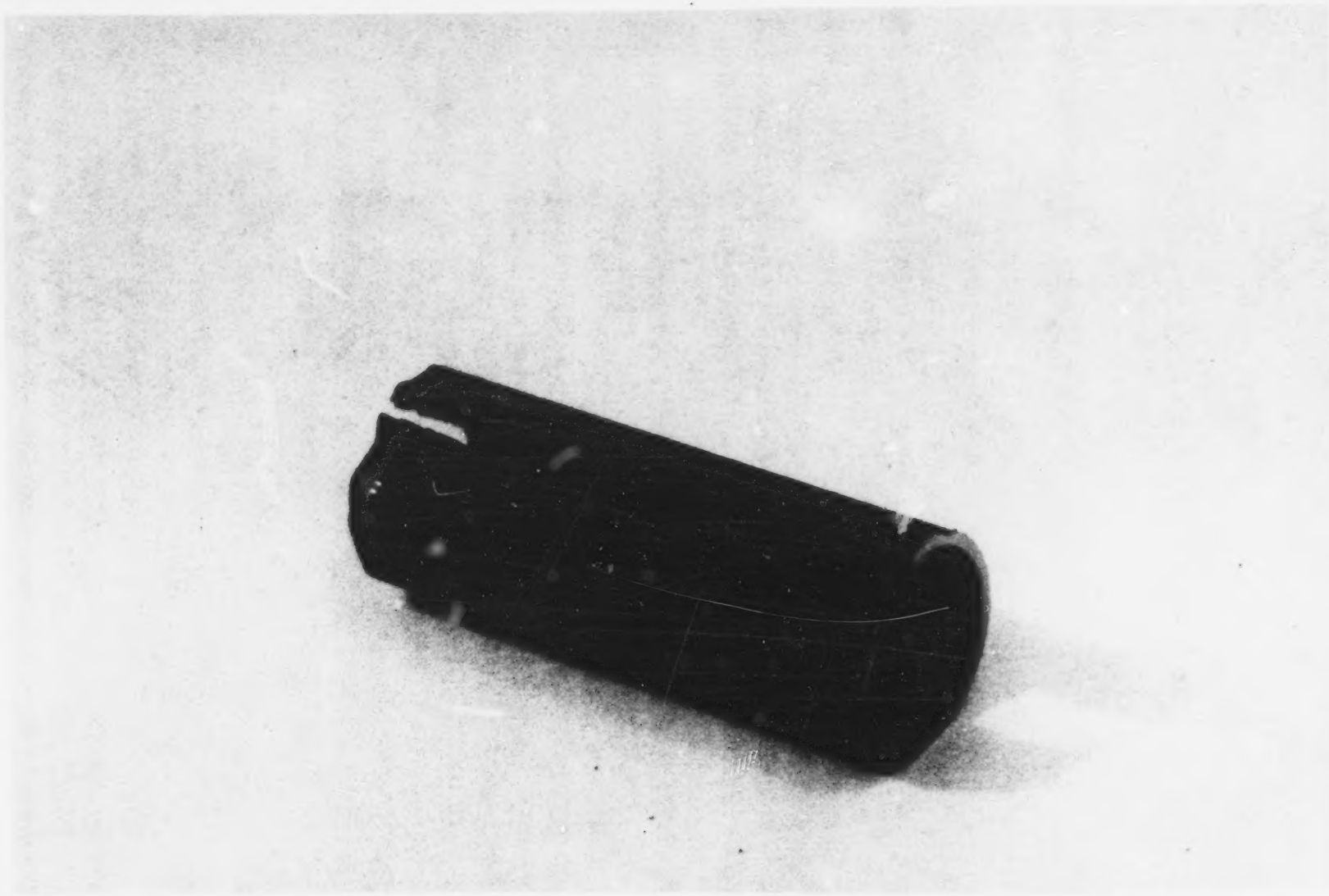


Figure 2. Photograph of specimen #7 from tube R43-C55 (GINNA) depicting through wall wear from a probable abrasion mechanism

BEST DOCUMENT AVAILABLE

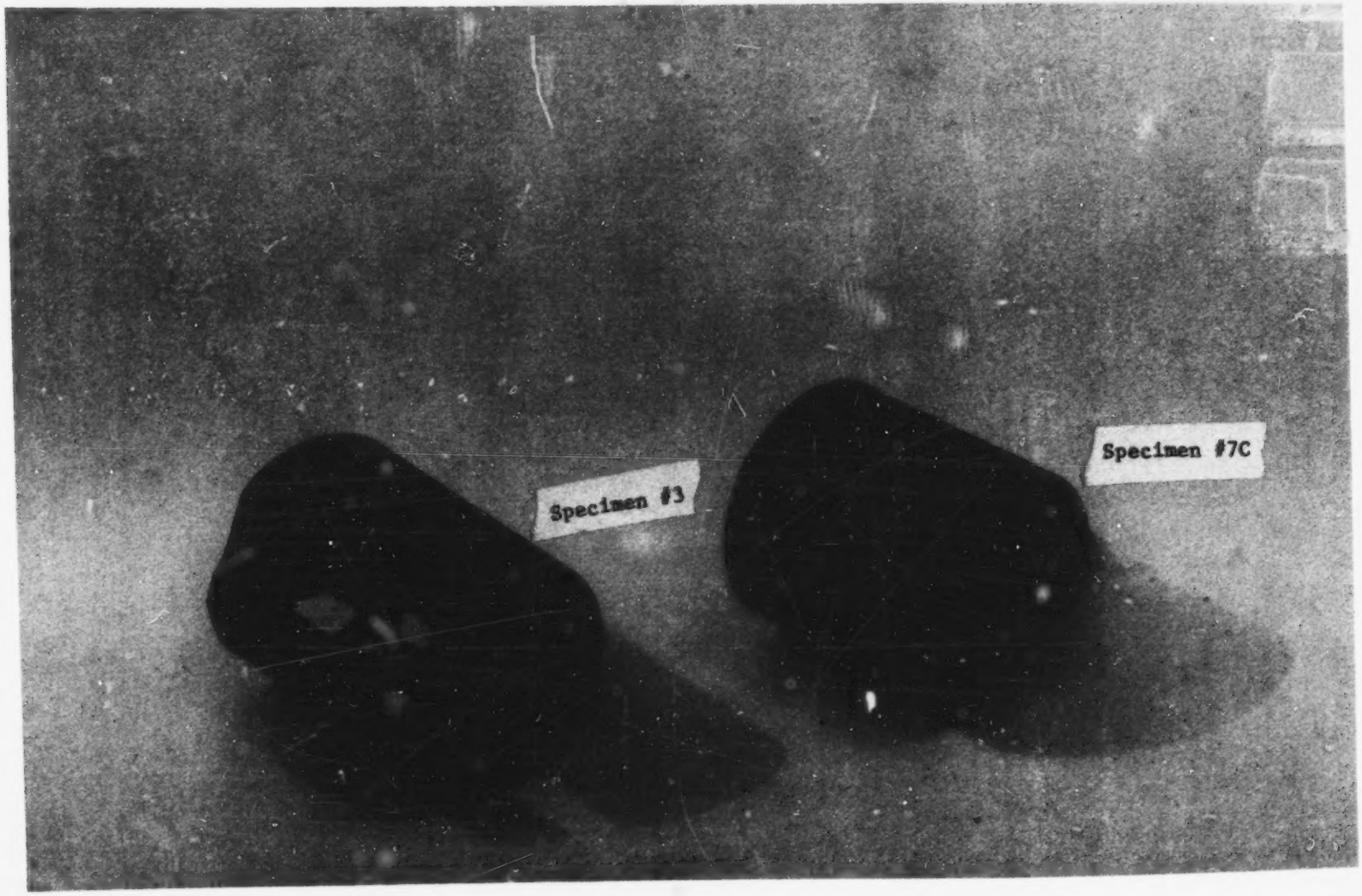


Figure 3. Photograph of specimen #3 from tube R43-C56 and #7C from tube R42-C55 (GINNA)

BEST DOCUMENT AVAILABLE

Figure 4 . Photograph depicting areas of apparent abrasion on specimen #6 of tube R44-C54 (GINNA)

BEST DOCUMENT AVAILABLE

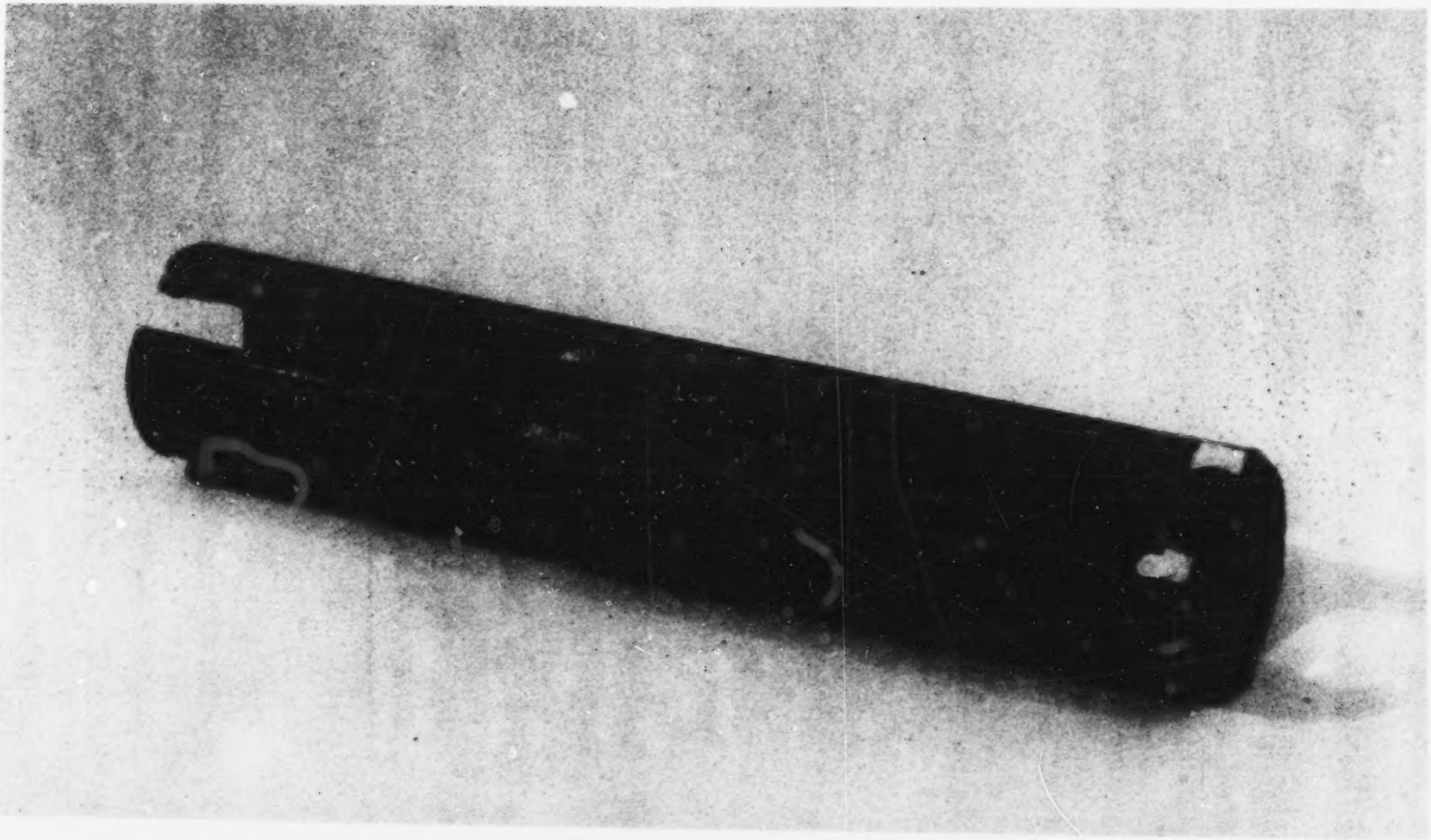


Figure 5. Photograph depicting severely abraded areas "through wall" on tube R43-C56 (GINNA)

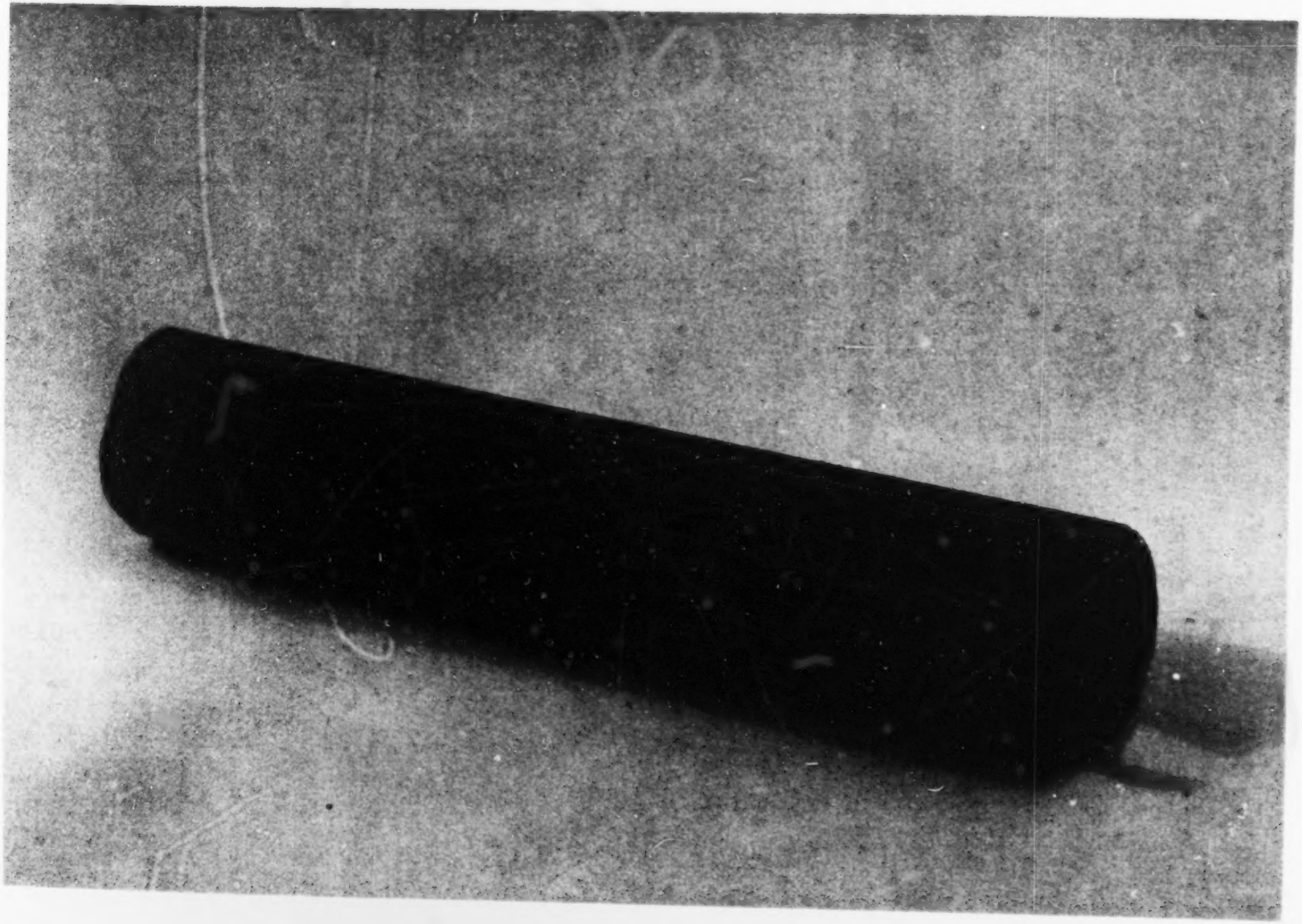


Figure 6. Photograph of severely abraded area and "through wall" thinning on specimen #1 of tube R43-C54 (GINNA)

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

GINNA STEAM GENERATOR

Diagram courtesy of
Rochester Gas & Electric

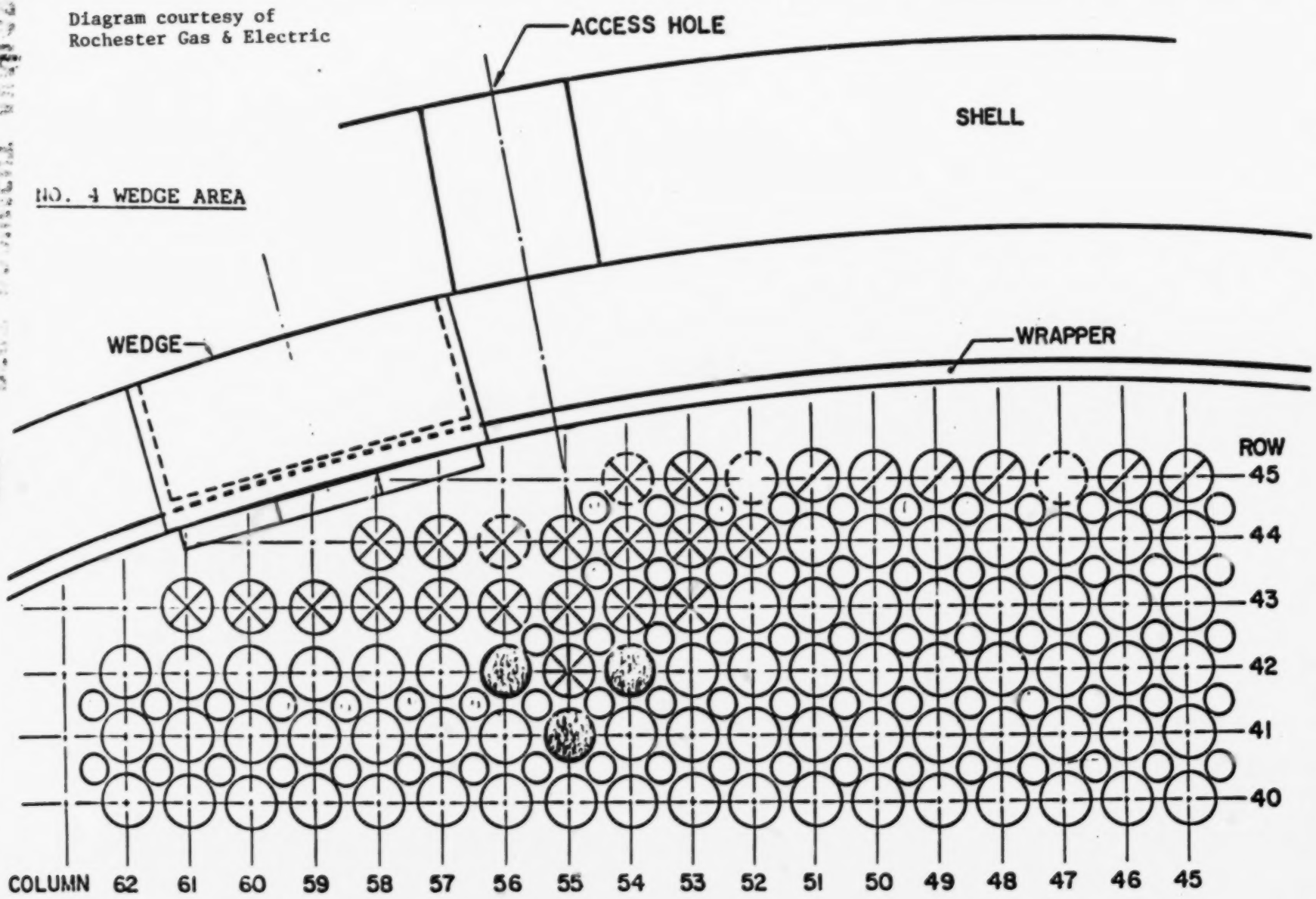


Figure 7. Diagram of Number 4 Wedge Area - Steam Generator "B" Hot Leg Side.

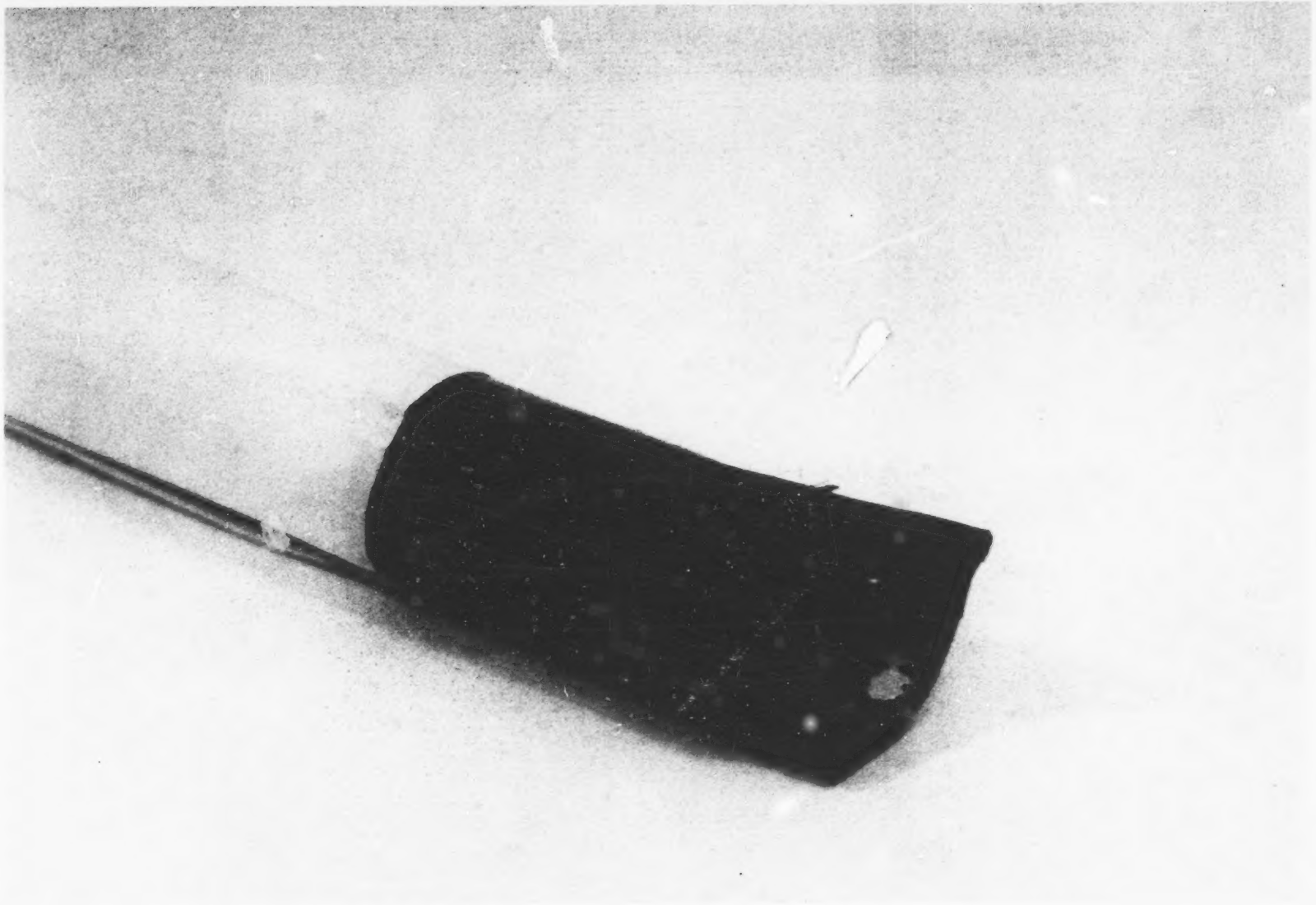


Figure 8. Photograph of collapsed area in tube R44-C57 (GINNA)

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

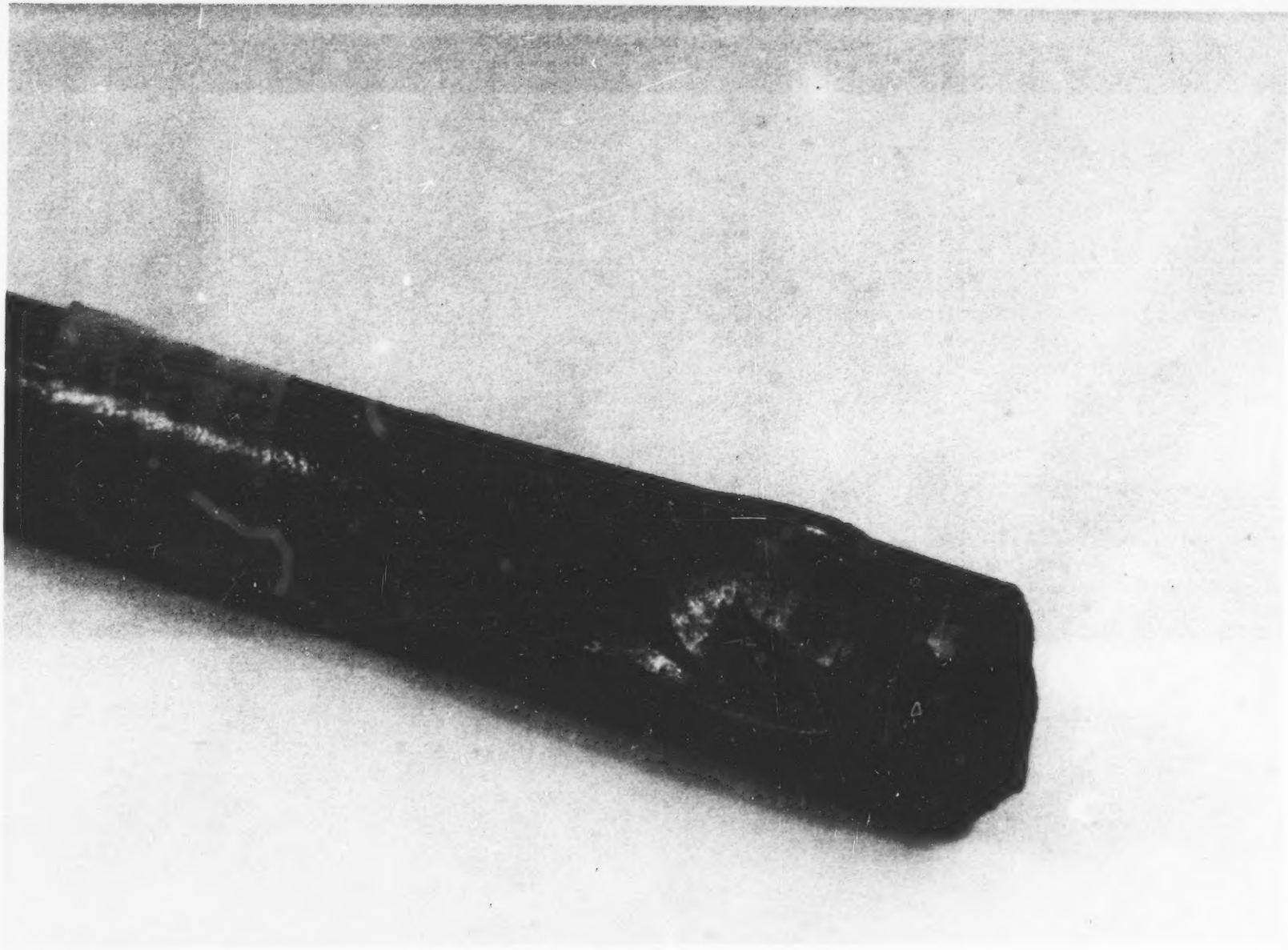


Figure 9. Photograph of apparently rubbed area in tube R8-C92 (GINNA)

BEST DOCUMENT AVAILABLE

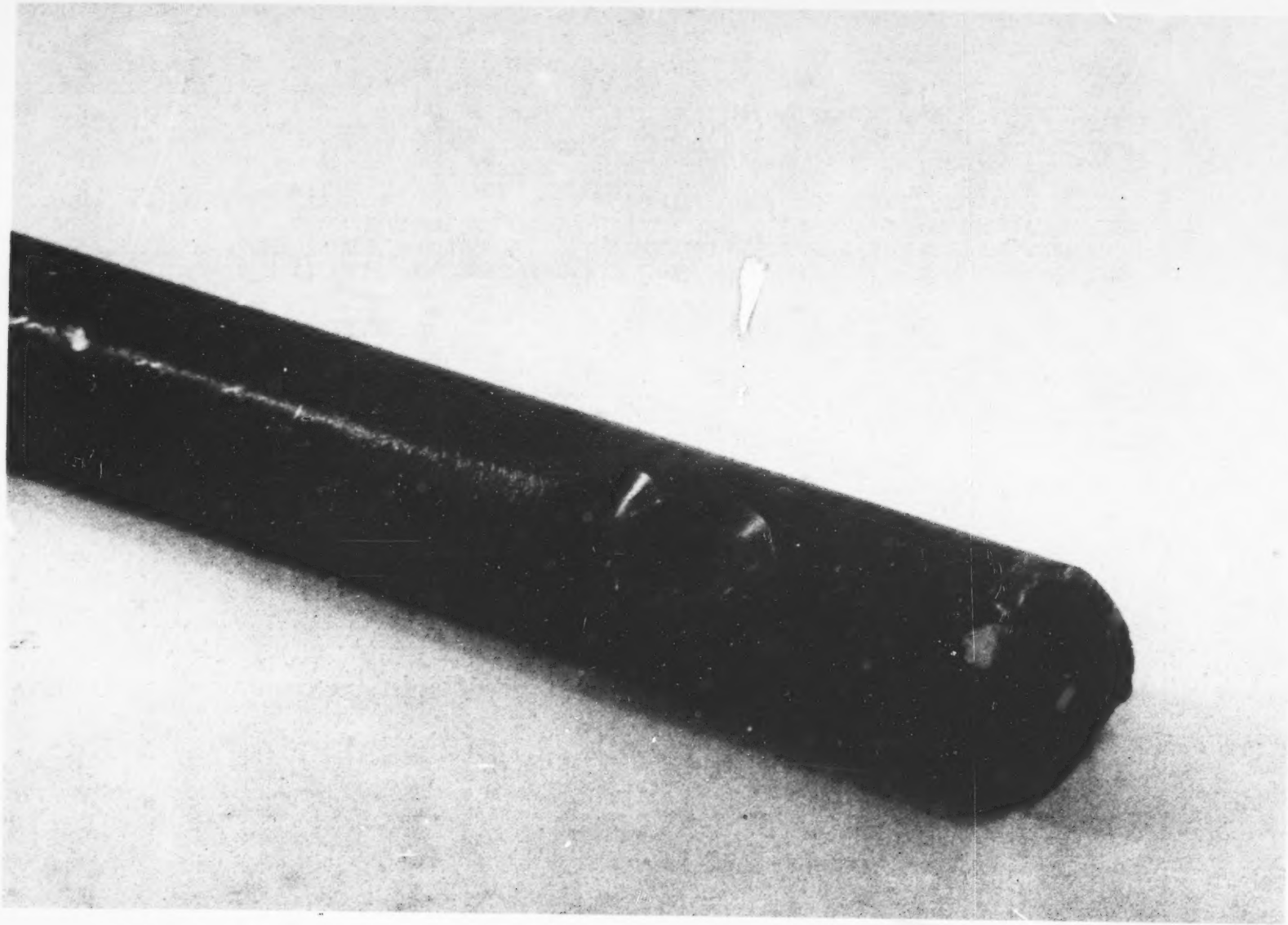


Figure 10. Photograph of abraded area in tube R10-C91 (GINNA)

Diagram courtesy of
Rochester Gas and Electric

GINNA STATION
STEAM GENERATOR
B-HOT LEG (INLET)

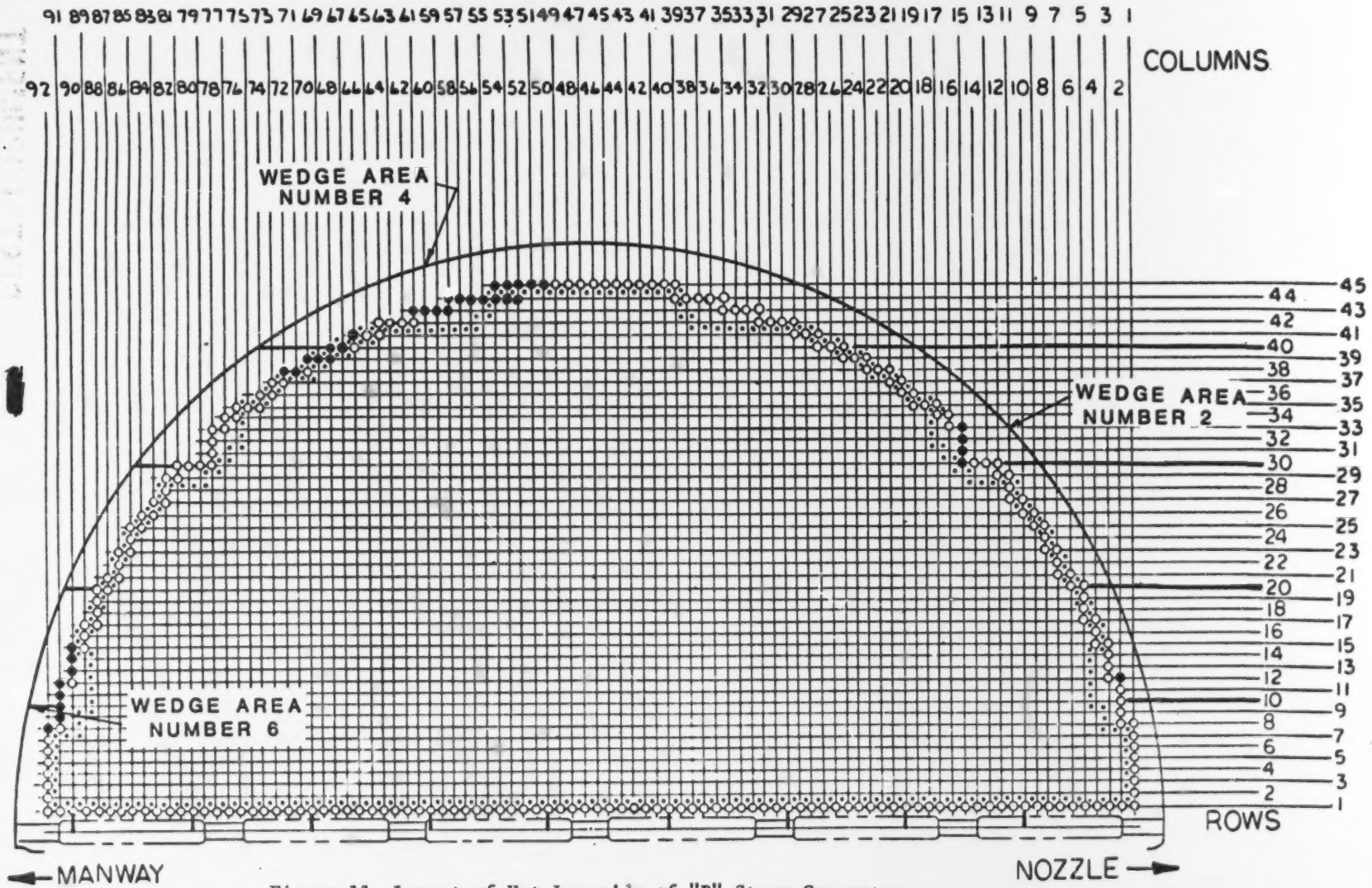


Figure 11. Layout of Hot Leg side of "B" Steam Generator depicting Wedge Areas

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

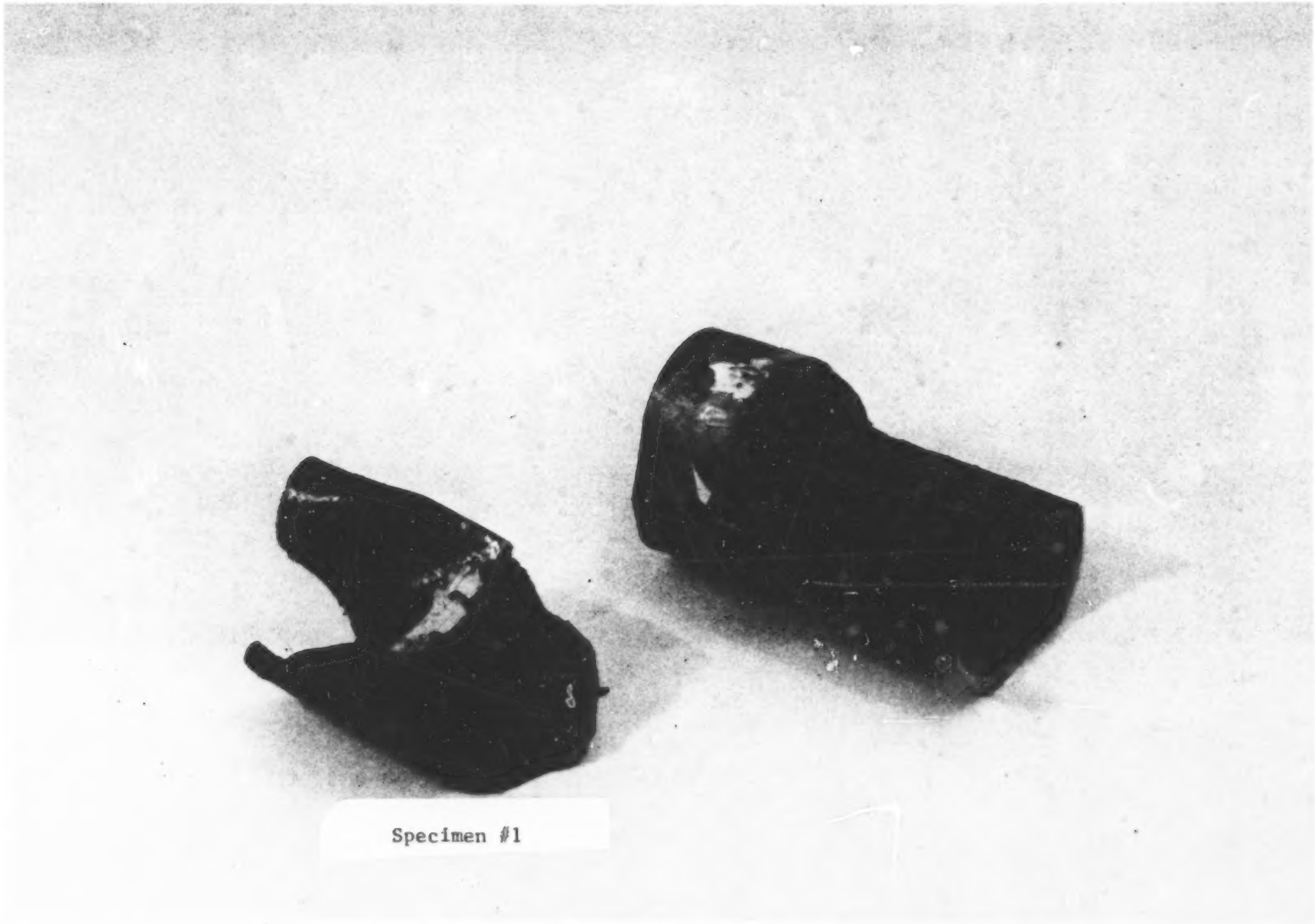


Figure 12. Photograph of two pieces of tube R44-C54 portraying considerable deformation

BEST DOCUMENT AVAILABLE

Figure 13. Photograph of severely deformed area in tube R44-C55 (GINNA)

BEST DOCUMENT AVAILABLE

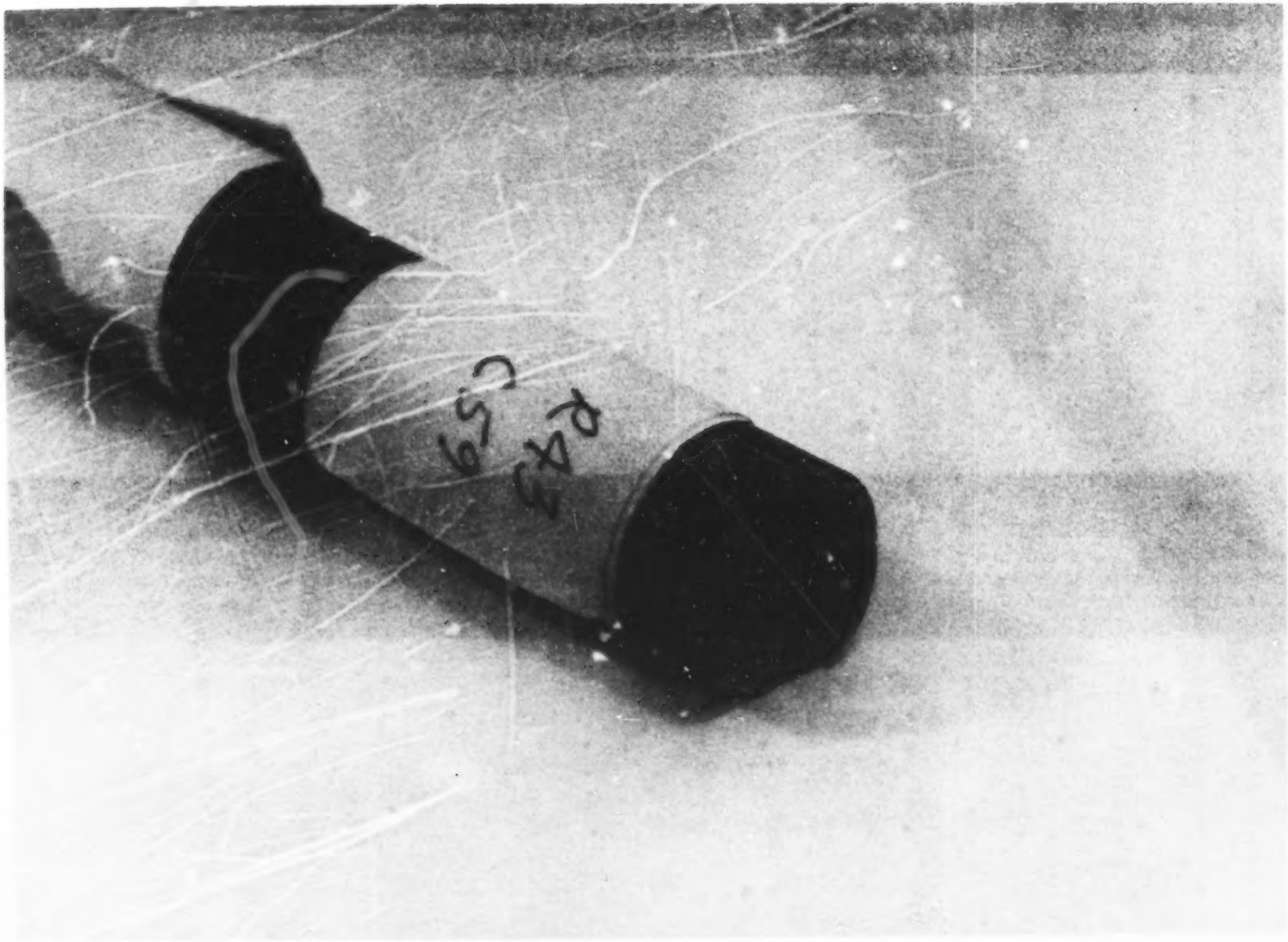


Figure 14. Photograph of probable "miscut" of Electric Discharge Machining (EDM) apparatus on tube R43-C59 (GINNA)

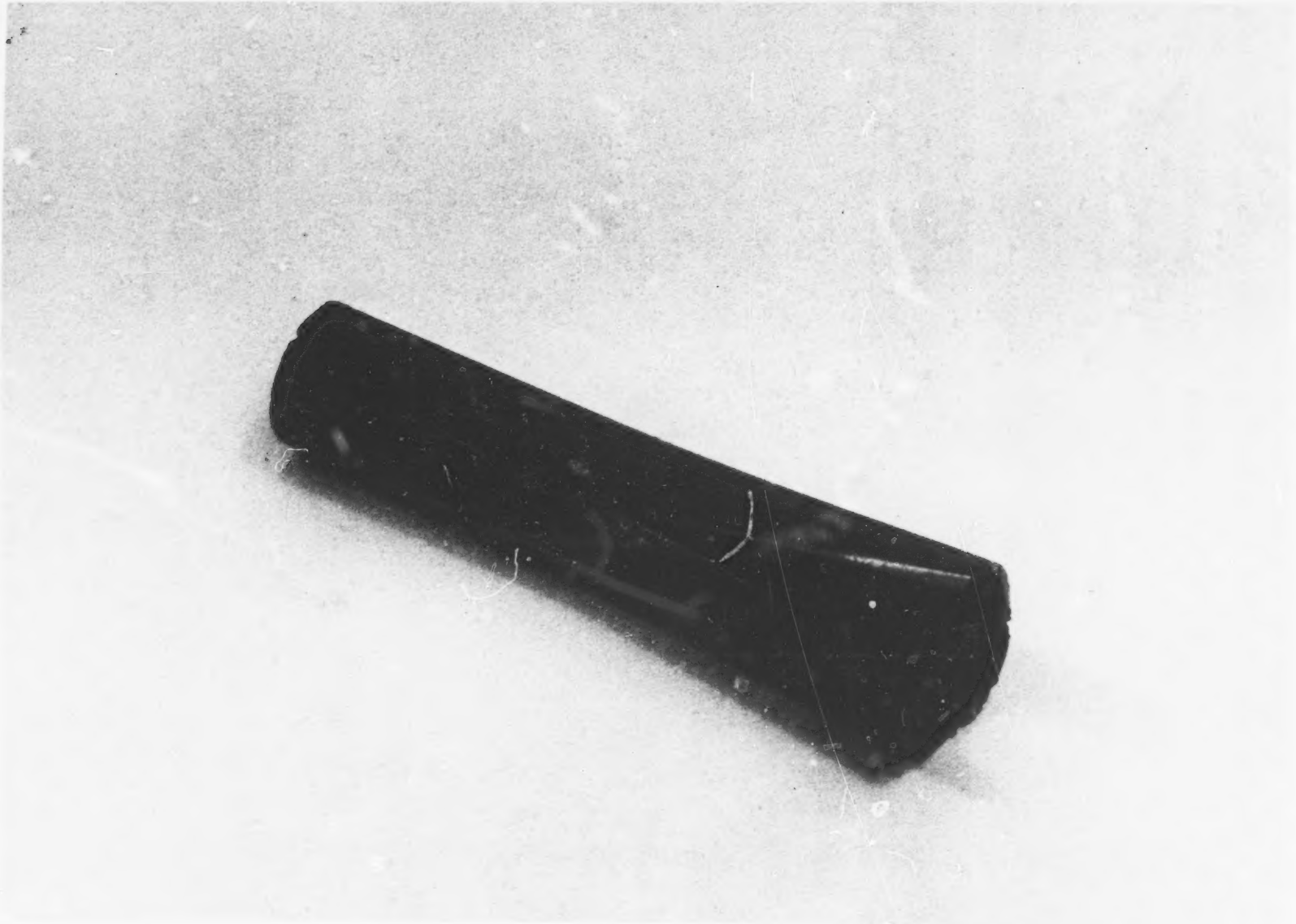


Figure 15. Photograph of "fish mouth" crack
in tube R42-C55 (GINNA)

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

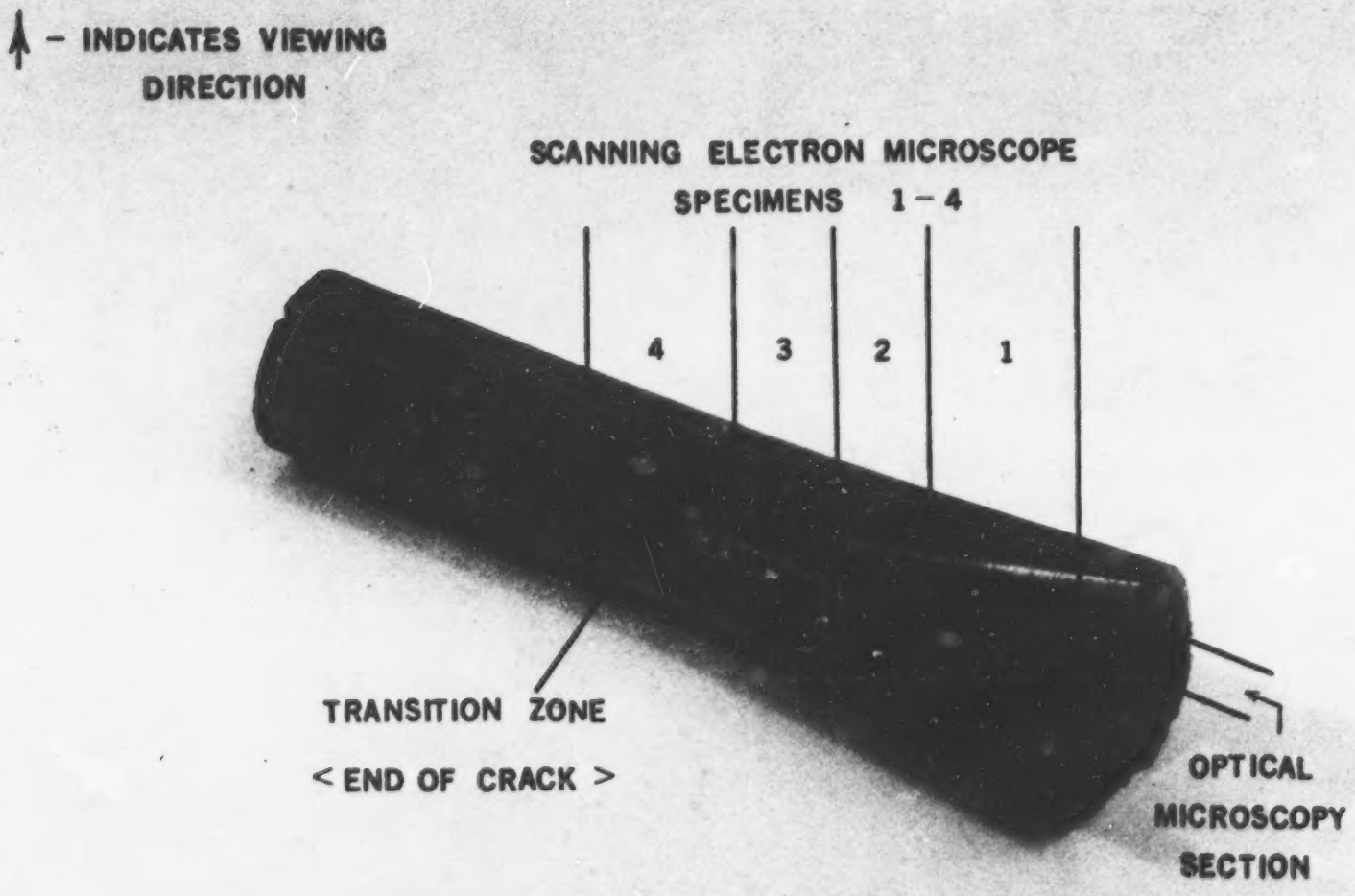
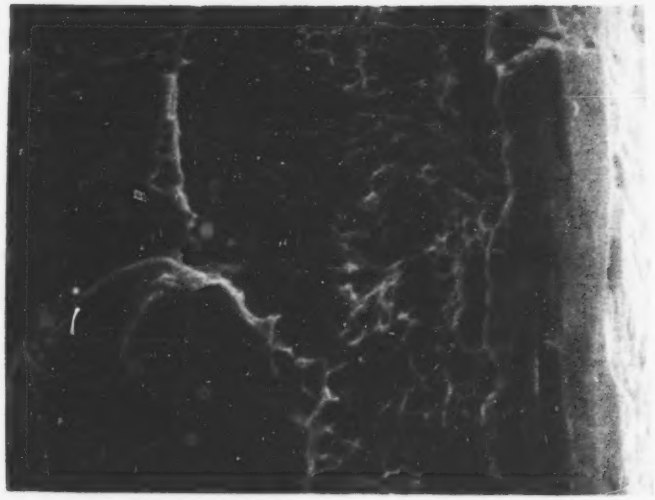
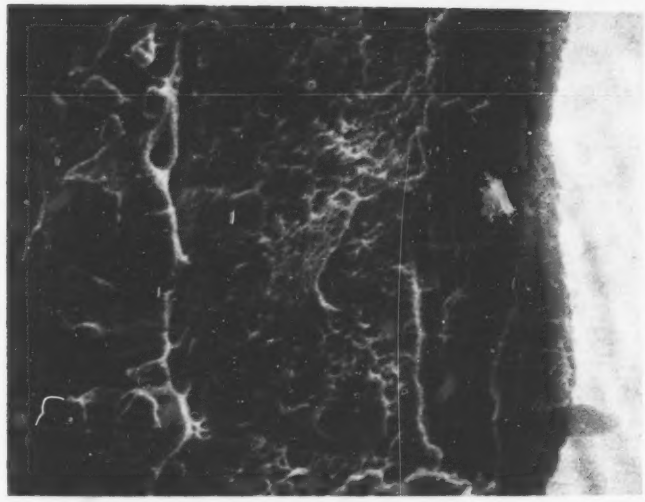


FIGURE 16. OVERLAY DEPICTING THE SECTIONING OF R42-C55 < GINNA >



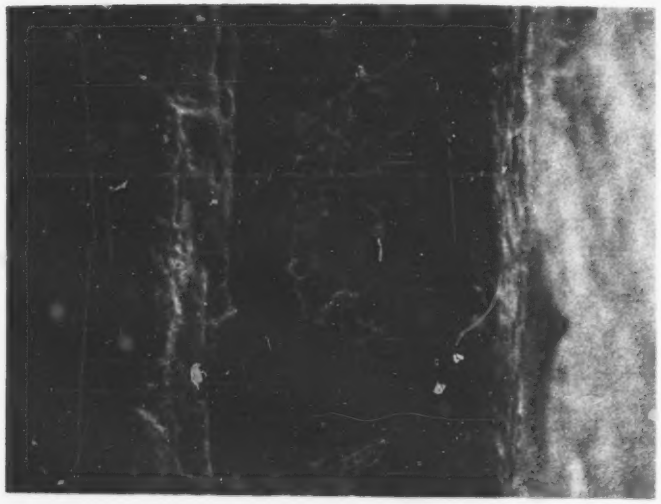
1000X

Figure 17. SEM photo of knife edge on R42-C55. Typical of "bulging" prior to ductile overload specimen #1



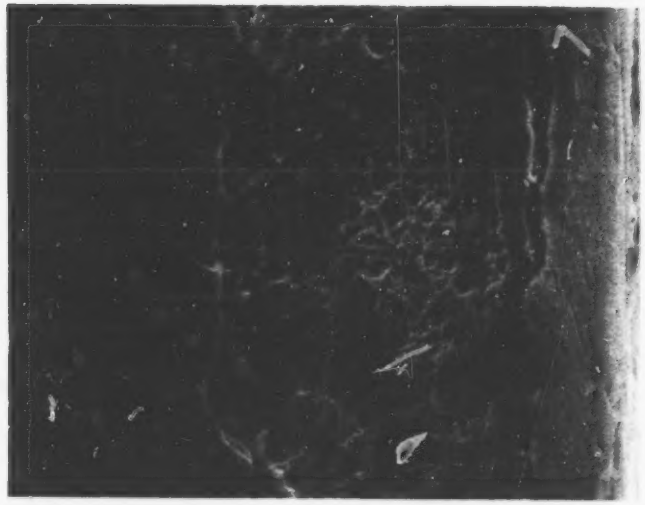
470X

Figure 18. SEM photo of knife edge on R42-C55. Elongation of dimples less pronounced. Specimen #2



500X

Figure 19. SEM photo of knife edge on R42-C55. Higher magnification. Specimen #2.



550X

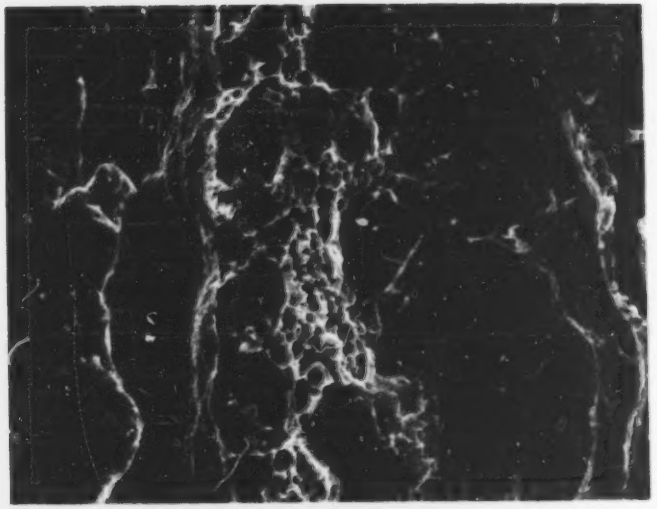
Figure 20. SEM photo of knife edge on R42-C55. Specimen #3

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

300X

Figure 21. SEM photo of knife edge on R42-C55 depicting impact after break. Specimen #3



750X

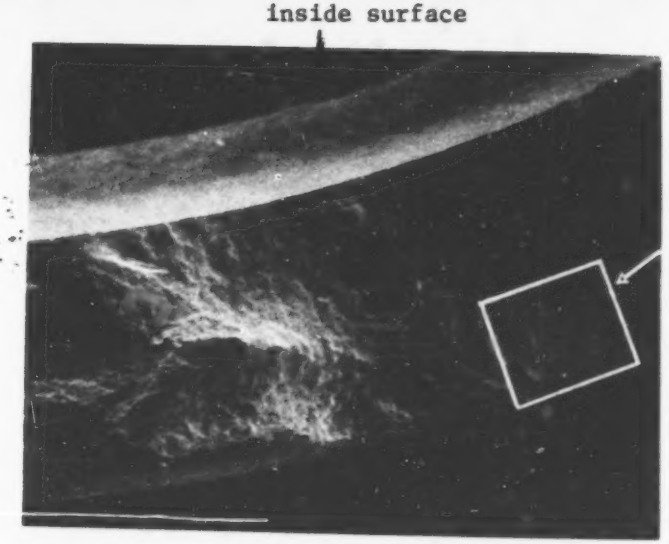
Figure 22. SEM photo of knife edge on R42-C55. Specimen #4

300X

Figure 23. SEM photo of transition of knife edge on R42-C55. Specimen #4

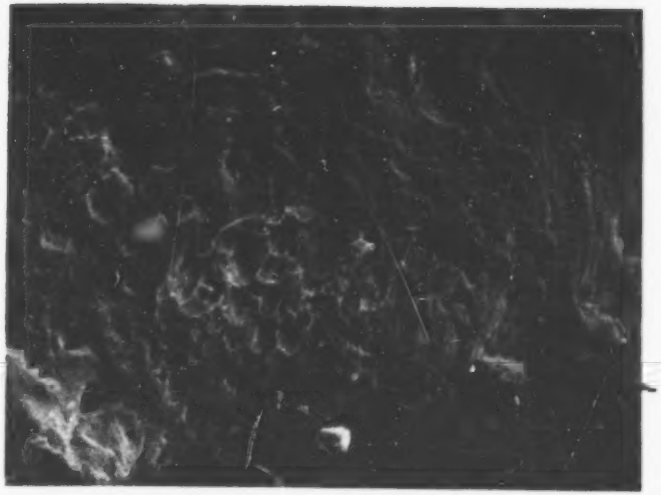
550X

Figure 24. SEM photo of transition of knife edge on R42-C55. Specimen #4



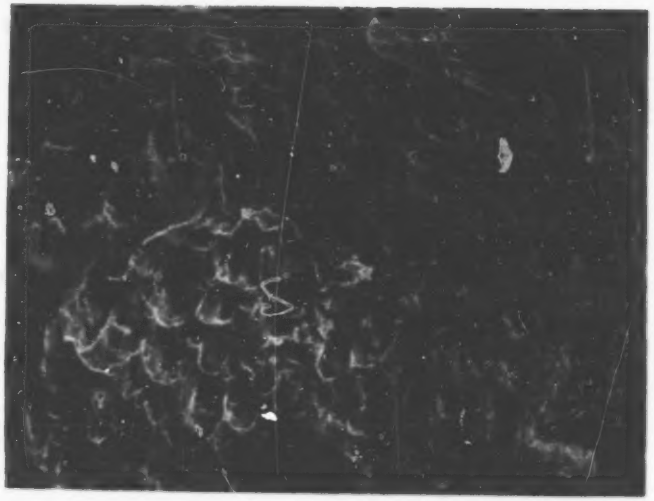
30X

Figure 25. SEM photo of "chevron" marks (indicative of fatigue failure) on Tube R44-C56 (top) near tube support plate



240X

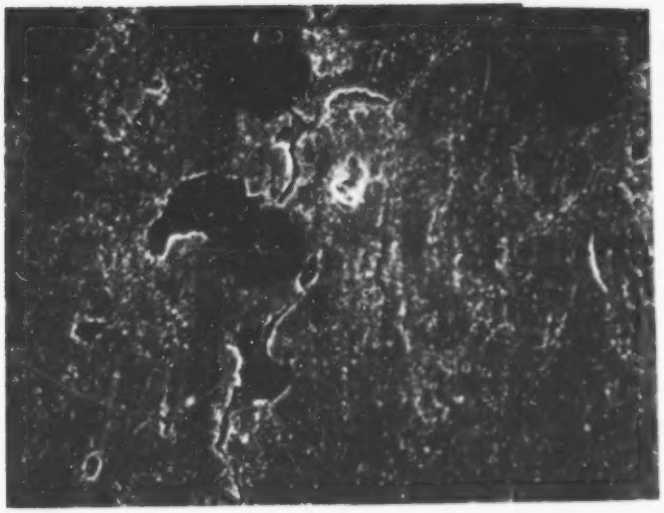
Figure 26. SEM photo of probable initiation site for cyclic fatigue failure of tube R44-C56



360X

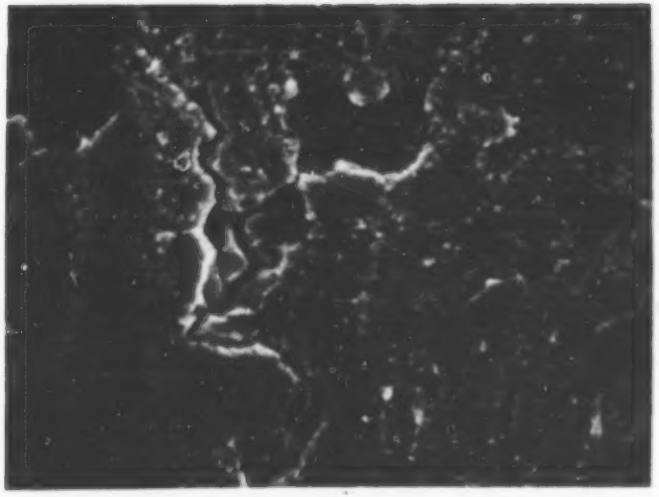
Figure 27. Higher magnification SEM photo of "initiation site" - Tube R44-C56

BEST DOCUMENT AVAILABLE



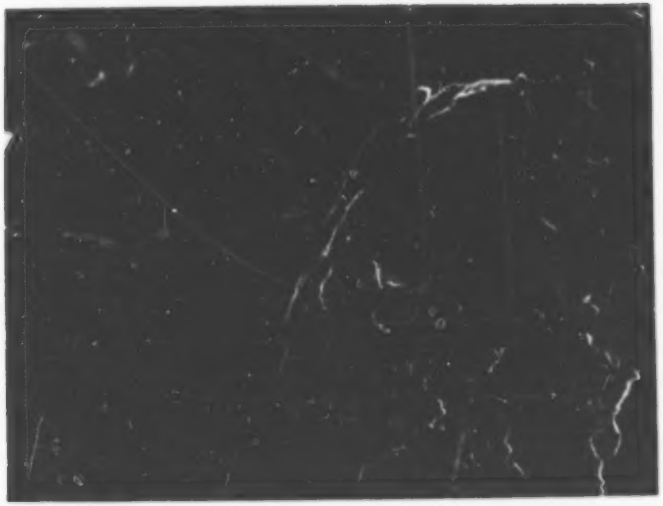
750X

Figure 28. SEM photo of inside surface of tube R43-C59 depicting area of possible deep etching



2000X

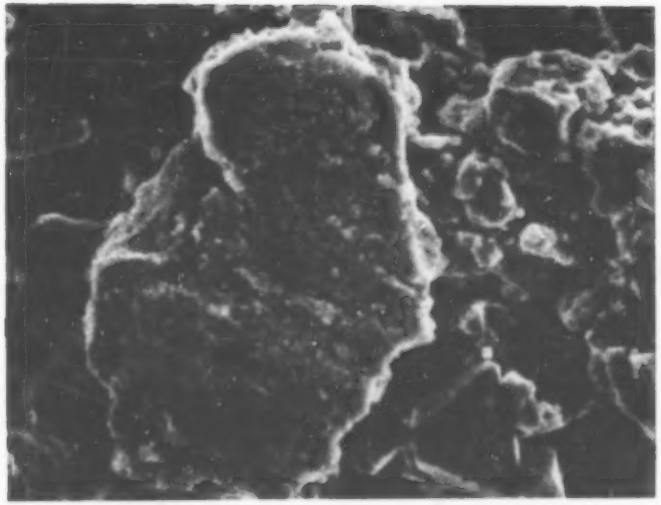
Figure 29. Higher magnification SEM photo of inside surface of tube R43-C59



390X

Figure 30. SEM photo of outside surface of abraded tube R11-C91

BEST DOCUMENT AVAILABLE



2000X

Figure 31. SEM photo of particle on inside surface of tube R8-C92 near rubbed area

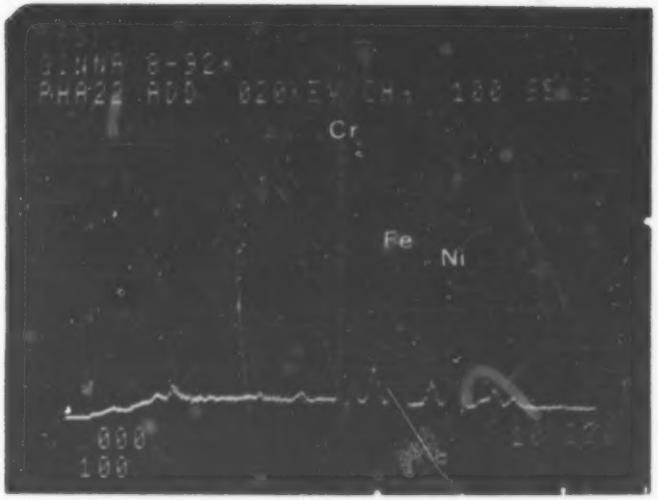
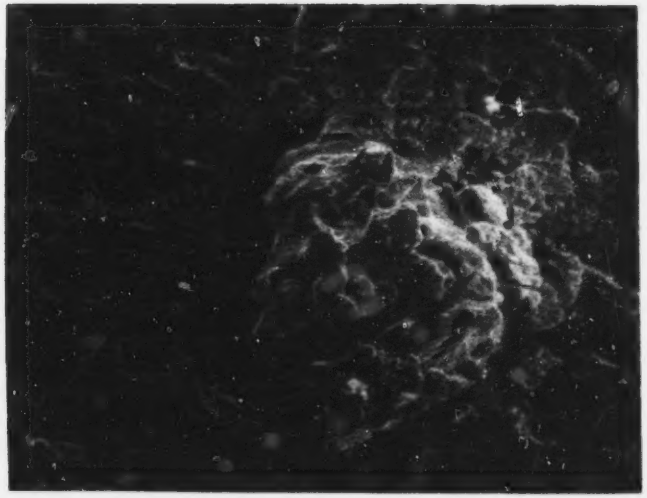


Figure31a. EDS scan of particle on inside surface of tube R8-C92 for constituents

BEST DOCUMENT AVAILABLE



430X

Figure 32. SEM photo of inside surface of tube R8-C92 depicting area of wall collapse

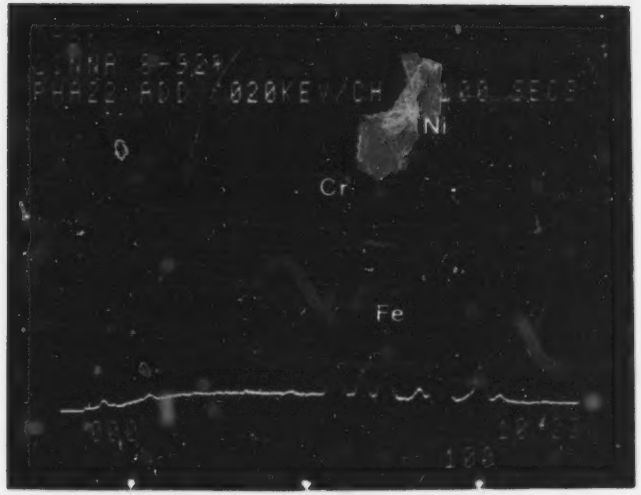
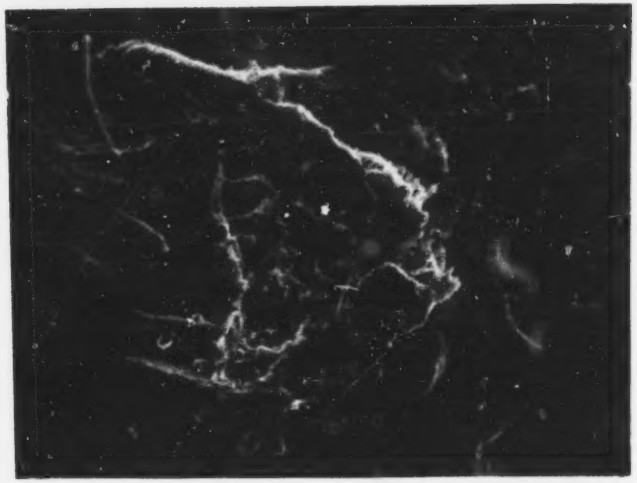


Figure 32a. EDS scan of inside surface of tube R8-C92 near collapse for constituents

240X

Figure 33. SEM photo of inside surface of tube R8-C92 depicting "etched" structure

BEST DOCUMENT AVAILABLE



1000X

Figure 34. Imbedded particle found on outside surface (O.D.) of R43-59

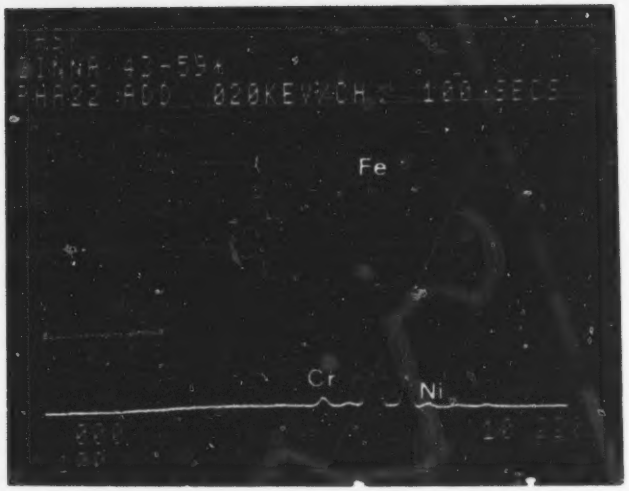
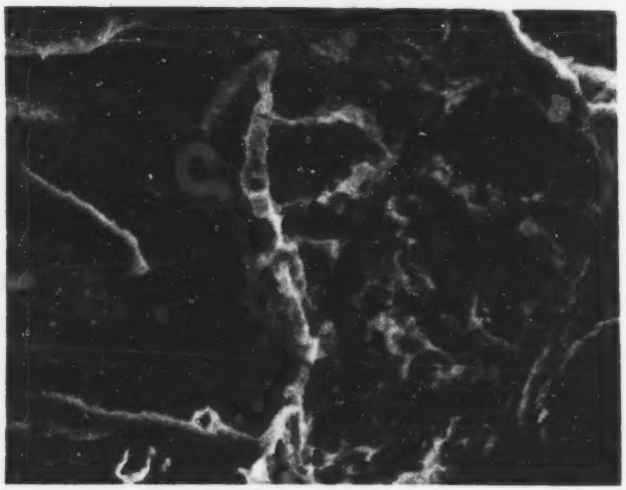
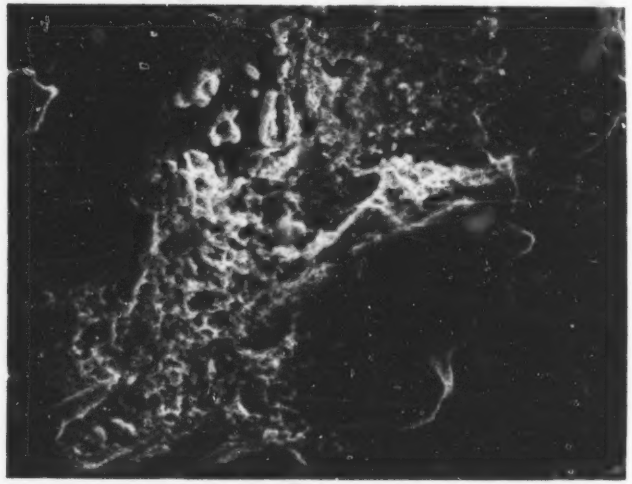


Figure 34a. EDS scan of imbedded particle found on R43-59



2200X

Figure 35. Higher magnification SEM photo of "imbedded" particle



1000X

Figure 36. SEM photo of another "smear" of iron (prior EDS scan is typical) found on outside surface of R43-59

BEST DOCUMENT AVAILABLE

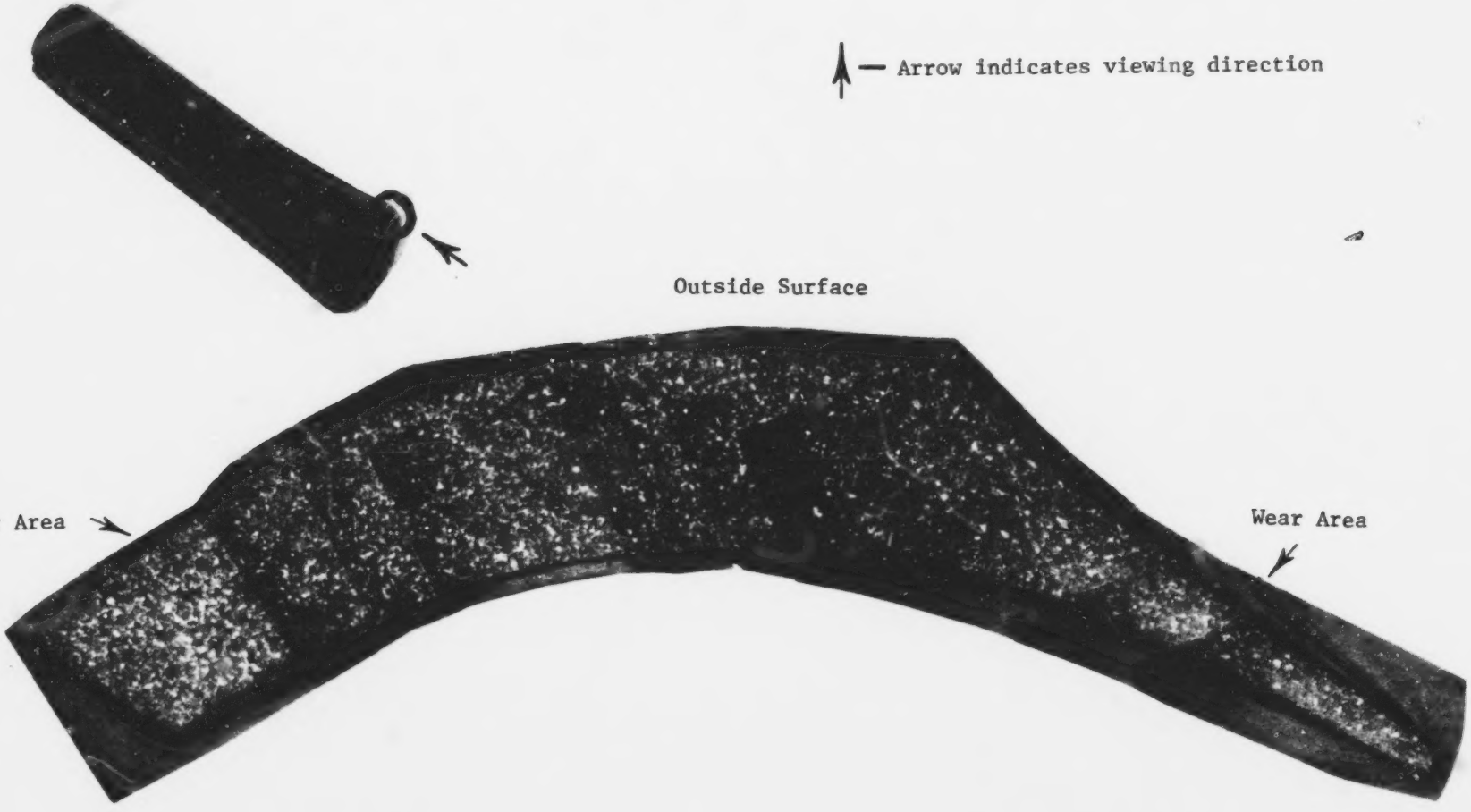
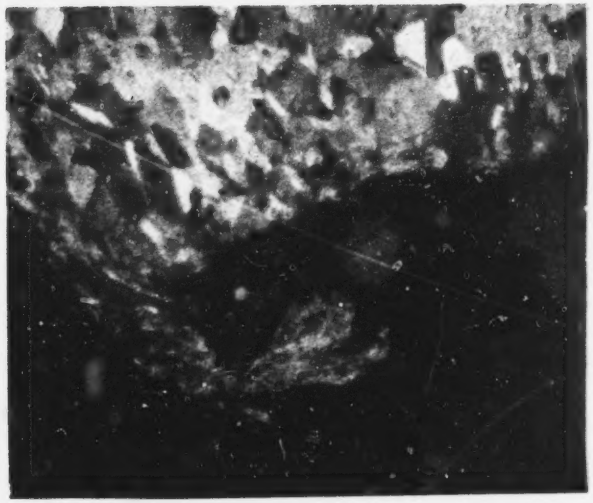


Figure 37. Optical photomicrograph of cross section of "Fishmouth" fracture (tube R42-C55) also shown is area of section relative to fracture. (Note: photomicrograph is optically reversed.

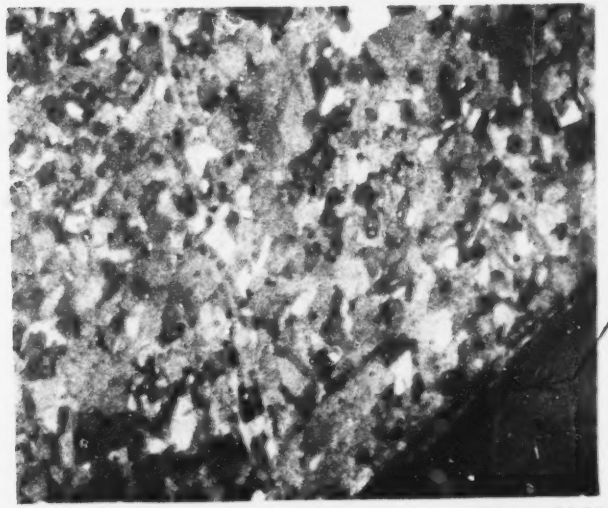
BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE



100X

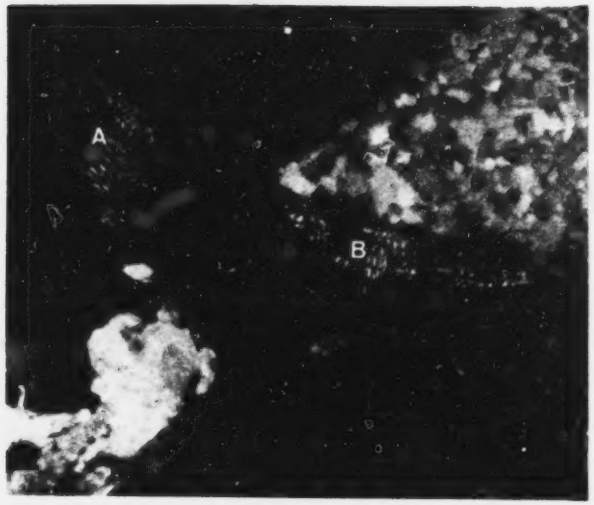
Figure 38. Optical photo depicting area of cold work on tube R8-C92.



100X

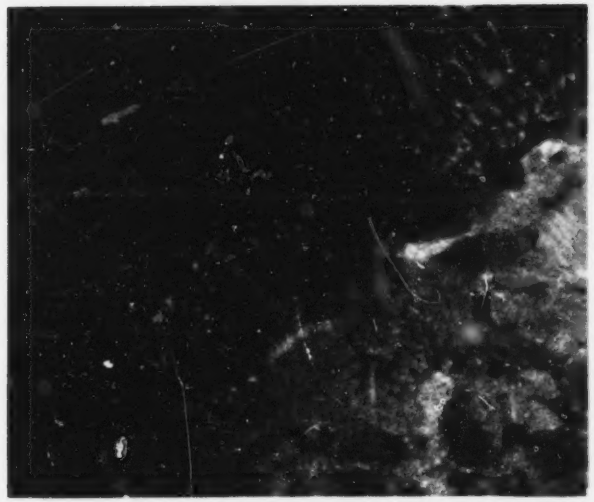
Figure 39. Optical photo displaying area of cold work on tube R10-C91.

Cold
Work
Areas



125X

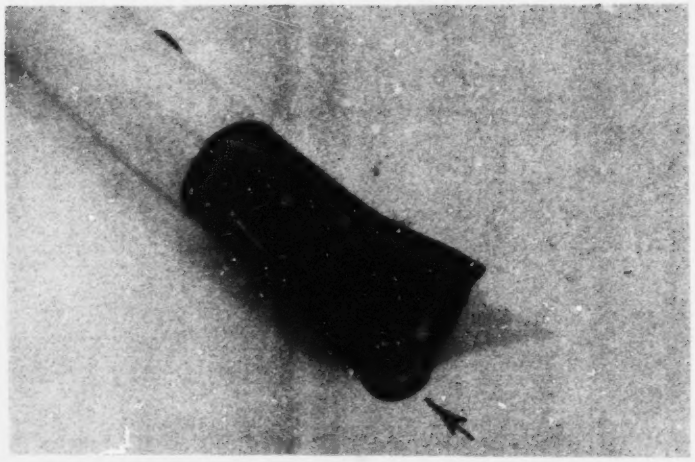
Figure 40. Low magnification photo of cold work on collapsed tube R44-C57.



400X

Figure 41. Higher magnification photo of cold work on tube R44-C57(Area B).

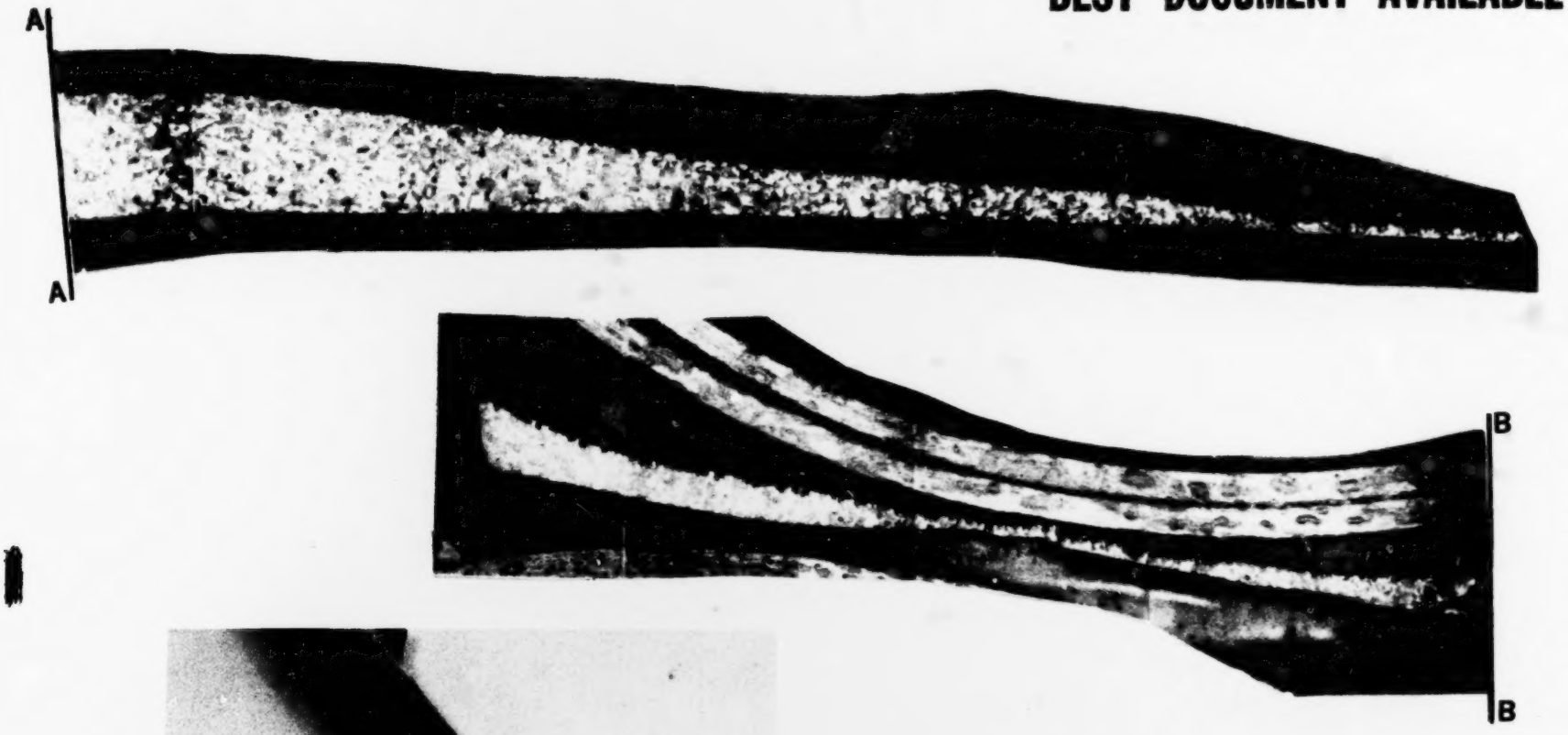
Figure 42. Cross sectional photomicrograph showing extent of damage endured by tube R44-C57. Also shown is area of section taken relative to collapse area.



Arrow indicates viewing direction

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE



Arrow indicates viewing direction

Figure 43. Optical cross section of segments from tube R8-C92 displaying extent of grain boundary etching.

APPENDIX B

BEST DOCUMENT AVAILABLE

TECHNICAL EVALUATION REPORT

RUPTURED TUBE ANALYSIS FOR GINNA

ROCHESTER GAS AND ELECTRIC CORP.
R. E. GINNA NUCLEAR POWER PLANT

NRC DOCKET NO. 50-244

FRC PROJECT C5506

FRC ASSIGNMENT 8

NRC CONTRACT NO. NRC-03-81-130

FRC TASKS 306, 307

Prepared by

Franklin Research Center
20th and Race Street
Philadelphia, PA 19103

Author: L. Leonard
G. P. Wachtell
FRC Group Leader: L. Leonard

Prepared for

Nuclear Regulatory Commission
Washington, D.C. 20555

Lead NRC Engineer: K. Wichman

May 12, 1982

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, or any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for any third party's use, or the results of such use, of any information, apparatus, product or process disclosed in this report, or represents that its use by such third party would not infringe privately owned rights.

Franklin Research Center
A Division of The Franklin Institute
The Benjamin Franklin Parkway, Phila., Pa. 19103 (215) 448-1000

CONTENTS

Section	Title	Page
1	INTRODUCTION	1
	1.1 Purpose of Review	1
2	TECHNICAL EVALUATION	2
	2.1 Meetings and Site Visits	2
	2.2 Documents	2
	2.3 Technical Efforts	3
	2.3.1 Metallurgical	3
	2.3.2 Foreign Objects	4
	2.3.3 Impact Model	5
	2.3.3.1 Theory	5
	2.3.3.2 Consequences of Alternative Model	6
	2.3.3.3 Effects of Particle Size	6
	2.3.3.4 Flow Model	9
	2.3.3.5 Laboratory Test Models	10
	2.3.4 Flow-Induced Vibration	11
	2.3.5 Tube Collapse	11
3	CONCLUSIONS	13
	3.1 Metallugical	13
	3.2 Flow Dynamics	13
	3.2.1 Theoretical Impact Model	13
	3.2.2 Tampa Flow Model	14
	3.2.3 Flow-Induced Vibration	14
	3.2.4 Test Models	14
	3.2.5 Scenario Leading to Tube Rupture	14

FOREWORD

This Technical Evaluation Report was prepared by Franklin Research Center under a contract with the U.S. Nuclear Regulatory Commission (Office of Nuclear Reactor Regulation, Division of Operating Reactors) for technical assistance in support of NRC operating reactor licensing actions. The technical evaluation was conducted in accordance with criteria established by the NRC.

BEST DOCUMENT AVAILABLE

1. INTRODUCTION

1.1 PURPOSE OF REVIEW

This Technical Evaluation Report (TER) documents the Franklin Research Center's (FRC) evaluation of work performed to determine the cause of a tube rupture in the Rochester Gas and Electric (RG&E) Corporation's Ginna B steam generator on January 25, 1982. An independent assessment was conducted of (1) the data generated for RG&E by Westinghouse Research and Development Center and by Battelle Columbus Laboratories and (2) the analysis carried out for the U.S. Nuclear Regulatory Commission (NRC) by Brookhaven National Laboratory.

In determining the actual cause of the tube failure, the primary concern was to ascertain whether other tubes in the generator were subject to similar failure on restarting the generator or whether the failure was due to circumstances specific to this particular tube in this particular generator.

BEST DOCUMENT AVAILABLE

2. TECHNICAL EVALUATION

The scope of the work included the following:

1. Attend meetings concerning the cause of the tube rupture.
2. Review documentation relevant to the tube rupture.
3. Visit Brookhaven National Laboratory to discuss work in progress and to view samples.
4. Prepare a technical evaluation report (TER) based on Tasks 1 through 3 above.

2.1 MEETINGS AND SITE VISITS

The following meetings were attended:

1. Rochester Gas and Electric Corporation, April 6, 1982
2. Brookhaven National Laboratory, April 14, 1982
3. Westinghouse Research and Development Center, April 27, 1982
4. Nuclear Regulatory Commission, Bethesda, MD, April 30, 1982

2.2 DOCUMENTS

The following documents were reviewed:

1. Examinations Performed on Tube R45C52 from the B Nuclear Steam Generator of the Rochester Gas and Electric Ginna Plant, August 10, 1978
2. Notes: RG&E/NRC Meeting, February 10, 1982
3. Steam Generator Tube Experience, NUREG-0886, February 1982
4. Summary and Notes on March 1, 1982 Meeting, RG&E/NRC, March 3, 1982
5. NRC Report on the January 25, 1982 Steam Generator Tube Rupture and R. E. Ginna Nuclear Power Plant, NUREG-0909, April 1982
6. Metallurgical Examination of Ginna Steam Generator Tubes, April 23, 1982 (also included in 8)

BEST DOCUMENT AVAILABLE

7. Documentation, Diagrams, Photographs, and Micrographs from Battelle Columbus Laboratories, Presented at a Meeting at Westinghouse R&D Center, April 27, 1982

8. Steam Generator Evaluation, Ginna Steam Generator Tube Failure Incident, April 26, 1982

9. Ginna Station Steam Generator Evaluation, NRC Meeting, April 30, 1982

2.3 TECHNICAL EFFORTS

2.3.1 Metallurgical

The documentation prepared by Westinghouse for RG&E, in particular Document 6, was definitive in representing the damage which had been incurred by the burst tube (R42C55) and by other tubes adjacent to it in Wedge Area 4. Tube rubbing and foreign object damage were clearly evident, and it is now certain that tube R42C55 had burst as a result of severe wall thinning along an approximately 4-inch length. This thinning could only have occurred as a result of rubbing against an adjacent tube; in turn, rubbing along such a long length would only have occurred if the adjacent tube had been severed at the tube sheet.

A sequence of tube rubbing and severing had initiated at the peripheral tubes. Based on all the evidence, including early documentation, it is most probable that the initial damage which led to plugging of the peripheral tubes had been foreign-object-induced. This damage consisted of nicks and/or wear. Once plugged, a tube would not be subject to further deterioration unless a foreign object were striking or rubbing it. As demonstrated by Westinghouse tests, repeated impacts can lead to the collapse of a plugged, non-leaking tube. A collapsed tube is then susceptible to fatigue failure (severing) owing to both vibration and further interaction with the foreign object. A severed tube would then rub against adjacent tubes until leaking or eddy current indications called for plugging or until a burst occurred.

There was no evidence that the chemical environment or metallurgical deficiencies in the Inconel 600 tubing played any role in the bursting of the tube. Furthermore, there was no indication of chemical attack on any of the

BEST DOCUMENT AVAILABLE

mechanically deteriorated tubes. In fact, fresh fracture details were evident on tubes that clearly had failed early in the sequence of events leading to the tube rupture.

It is important to note that (1) a critical event in the sequence of events leading to the tube failure was the continuing degradation and ultimate severing of plugged tubes and (2) a plugged tube was no longer subject to inspection in the routine maintenance program. Accordingly, there was no way of anticipating either the type of failure that occurred or the degree of plugged tube degradation in Wedge Area 4.

The failure analysis performed at Battelle and Brookhaven corroborated the Westinghouse results. None of the examined tubes exhibited deterioration due to any mechanism other than wear and fatigue in conjunction with foreign object damage.

The flow model and simulated wear tests conducted by Westinghouse (Document 9) indicate that nothing in the postulated sequence of events leading to the failure is inconsistent with experimental data.

Television viewing of in-place peripheral tubes revealed some tubes with minor dings or nicks on the outer diameter (OD). On samples removed from the steam generator, it was evident that such damage was minimal and should not detract from the tube's service capability. Accordingly, as long as excessive eddy current indications are not noted, it does not appear necessary to remove or plug other tubes with similar indications.

2.3.2 Foreign Objects

The foreign objects recovered from the generator are tabulated on pages 3.5-1 and 3.5-2 of Document 8. The largest items were three pieces of 0.5-in thick carbon steel plate, one about 4 x 6.3 in, one 1.5 x 3.5 in, and one eliptical with axes 2 and 2.4 in. The Westinghouse calculations and tests demonstrated that the largest object would readily induce the type and extent of damage noted on the peripheral tubes.

Since the presence of such foreign objects had never been suspected, no inspections had been carried out to assure that this type of debris was not

BEST DOCUMENT AVAILABLE

present. If a video inspection system or an acoustic monitoring system had been in place, it now appears certain that not only would the foreign object have been found, but the severe deterioration of the peripheral tubes would also have been detected.

2.3.3 Impact Model

2.3.3.1 Theory

In the theory given in Document 8, an impacting mass (foreign object) is accelerated by cross flow in the space between the wrapper and the outermost (peripheral) tubes in a wedge area. Upon impact with a tube, the impacting mass moves together with the tube. The tube moves in its lowest resonant mode. The tube is regarded as "fixed-fixed" at the tube sheet and the first support plate. The maximum force between the impacting mass and the tube must be sufficient to cause local plastic deformation in order to contribute to the eventual collapse of the tube. Collapse of a plugged tube will occur as a result of a sufficient number of impacts, especially if there is excess pressure outside the tube. This excess pressure, about 1,000 psi, will occur if the plugged tube has no leak.

This model of the interaction between impacting object and tube is open to question. There is a local deformation near the location of the impact. This local deformation is entirely elastic unless the peak stress exceeds the elastic limit, whereupon some plastic deformation will occur. We now assume that the impact is borderline, that is, not quite strong enough to cause plastic deformation. The elastic deformation may be modeled as a spring with a large spring constant, k. The impacting mass, m_i, strikes this spring, which is mounted on the effective mass, m_t, of the tube. m_t is, in turn, attached to ground via another spring, with spring constant k_1.

The resonant frequency of m_i joined to m_t by k is very high compared to the resonant frequency of m_t joined to ground by k_1. Consequently, the

BEST DOCUMENT AVAILABLE

BEST DOCUMENT AVAILABLE

duration of contact between the impacting mass and the tube is short compared to the period of the tube oscillation. Spring k_1 is negligibly deflected during the impact. The theoretical calculation of the peak force should not be based on the model used in Document 8.

2.3.3.2 Consequences of Alternative Model

If m_i impacts with velocity v_i, its momentum and kinetic energy are, respectively, $m_i v_i$ and $m_i v_i^2/2$. The peak force occurs when the distance between the ends of the spring reaches its minimum. This occurs when m_i and m_t have the same velocity. Conservation of momentum requires that this volocity be $m_i v_i/(m_i + m_t)$. The combined kinetic energy is $(m_i + m_t)\ (m_i v_i/(m_i + m_t))^2/2$. Subtracting this from $m_i v_i^2/2$ we obtain the energy (elastic plus plastic, if any) stored in the spring. From this, we find the fraction of the initial kinetic energy that is delivered to the spring. This fraction is $m_t/(m_i + m_t)$. If m_i is small compared to m_t, almost all the incoming kinetic energy is delivered to the spring.

2.3.3.3 Effect of Particle Size

We consider a reference impacting particle of mass m_o and cross section area (perpendicular to the flow) A_o. We also consider a geometrically similar particle with linear dimension s times that of the reference particle. The mass of the particle is $m_o s^3$ and its cross section area is $A_o s^2$. The acceleration produced by the drag force is -du/dt, given by

$$m_o s^3\ du/dt = cA_o s^2 \rho_w u^2/2$$

where:

$u = v_w - v$

v_w = velocity of water = constant

v = velocity of particle

ρ_w = density of water

c = drag coefficient = 1

$B = c\rho_w A_o/2m_o$

BEST DOCUMENT AVAILABLE

This equation may be integrated, leading to

$$v = v_w - \frac{1}{\frac{B}{s}t + \frac{1}{v_w}}$$

where v is assumed to be = 0 for t = 0. The distance traveled in time t is found by another integration to be

$$x = v_w t - \frac{s}{B} \ln\left(\frac{B}{s} v_w t + 1\right)$$

Eliminating t between these two equations,

$$\frac{Bx}{s} = y - \ln(y+1)$$

where

$$y = \frac{v}{v_w - v}$$

A plot of Bx/s versus v/v_w is shown in Figure 2-1. For v small compared to v_w, y is small and Bx/s is approximately $y^2/2$, so that, for large s compared to Bx,

$$\frac{v}{v_w} = \frac{1}{1 + \frac{1}{y}}$$

$$= \frac{1}{1+\sqrt{\frac{s}{2Bx}}} \quad (v << v_w)$$

If s is small compared to Bx, y is large and v is nearly equal to v_w.

For large s, v is roughly proportional to $1/\sqrt{s}$. The kinetic energy of the impacting particle (assuming that the travel distance, x, before impact is the same for all particles) is proportional to $m_o s^3 (1/\sqrt{s})^2$. That is, the kinetic energy is proportional to s^2.

For small s, the kinetic energy is proportional to s^3. Applying the fraction $m_t/(m_i + m_t)$ found in Section 2.3.3.2, the energy delivered to the spring is proportional to

$$\frac{s^n}{1 + \frac{m_o}{m_t} s^3}$$

BEST DOCUMENT AVAILABLE

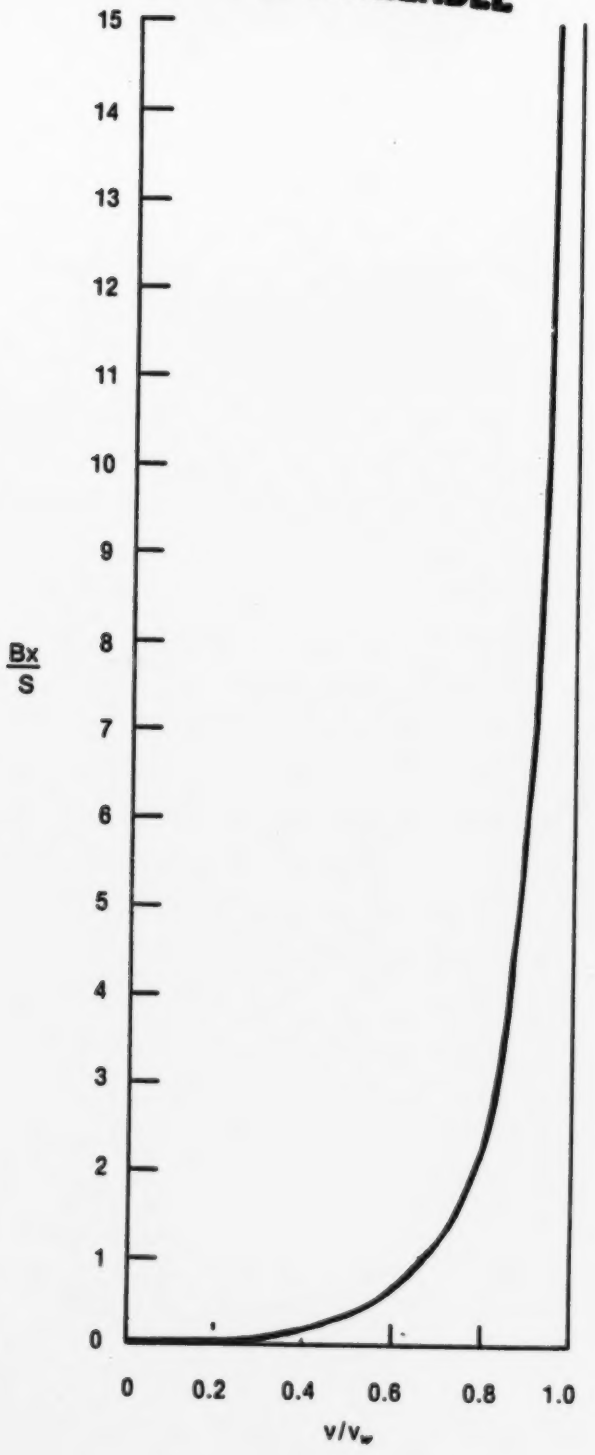


Figure 2-1. Bx/s versus v/v_w

BEST DOCUMENT AVAILABLE

where n = 2 for large s, and n = 3 for small s. In Document 8, the impacting mass was assumed to be 0.074798 lb-sec^2/in, and in two models of the impacted tube, the effective mass of the tube was 0.03767 and 0.01068 lb-sec^2/in. Therefore, m_o is less than m_t, so that for small s, the term $m_o s^3/m_t$ may be neglected compared to unity.

This shows that for small s, the stored energy is roughly proportional to s^n where n is between 2 and 3. Consequently, if the energy delivered to the spring is the maximum possible without plastic deformation when s = 1, appreciable plastic deformation will occur with an impacting mass that is, say, 1.5 times as large, and plastic deformation will be avoided by a wide margin with an impacting mass that is, say, half as large.

For this reason, it is not necessary to have a very exact theoretical calculation of the mass that will cause incipient plastic strain. It is sufficient to have a rough estimate. The experimental studies using the flow model in the Westinghouse Tampa facility appear to supply this rough estimate. Although the model discussed here can be studied further, by quantifying the value of m_t, and by considering an oscillatory flow component, as was done in Document 8, the present discussion is sufficient to justify the conclusion that small foreign objects will not cause plastic deformation.

If an impacting mass that is, say, 0.1 times as large as the largest mass that was studied can be detected (by television or other means), one may be sure that any masses that remain undetected will be too small to cause deformation of the tube. Since particles as small as 0.25 inch diameter spheres were actually detected and recovered, one may be confident that objects that are large enough to cause more than superficial tube damage will be removed.

2.3.3.4 Flow Model

The flow model in the Westinghouse Tampa facility appears to be well suited to the purpose of studying the impact of foreign objects with peripheral tubes. In addition to the study that was done with a model of the largest foreign object, it is possible that impact peak forces due to smaller

BEST DOCUMENT AVAILABLE

objects were also measured and compared with the minimum static concentrated load capable of causing local plastic deformation. In addition, the mobility of small foreign objects may have been observed. The large foreign object remained trapped in the modeled wedge area for the duration of the test run that was shown on videotape at the April 30, 1982 meeting. It could be seen to strike the target tube several times in approximately the same spot. This supports the scenario for damage, in which a peripheral tube is ultimately flattened and torn so that it becomes separated from the tube sheet and then wears its neighboring tubes. If observations have also been made with sufficiently small foreign objects, with s = 0.1, say, there may be experimental support for the expection that such small objects are so highly mobile that they never strike a tube in the same place twice. But even if such experiments have not been performed, it is reasonable to conclude that if objects larger than, say, 0.25 inches in typical dimension are removed, the above scenario will not be repeated.

2.3.3.5 Laboratory Test Models

Two laboratory test setups were shown after the meeting on April 27, 1982, the first of which is shown in Document 9. In this test, a model impacting mass is propelled upward against the side of a horizontally mounted tube specimen. The mounting fixture enables an external pressure to be applied to the tube. The impacting peak force is measured, the tube is moved axially or rotated about its axis between successive impacts, and the tube is backed so that it does not bend.

This experiment appears to be well designed to yield valid data relating (1) the peak force to the occurrence of permanent deformation and (2) the effect of external pressure in collapsing the tube once substantial ovality is produced.

Since a statically applied force produces the same local stresses and strains as the same peak force applied dynamically, it would appear to be sufficient to apply the force statically. This might have led to a simpler experiment. Furthermore, backing the tube to prevent it from bending should make no difference in the final result, provided the peak applied force

BEST DOCUMENT AVAILABLE

is the same with and without backing. However, these comments do not detract from the validity of the test as actually performed.

The second test setup uses a length of tube clamped at both ends and caused to vibrate at its resonant frequency. A blunt chisel is supported so that the vibrating tube makes contact with it. In this way, the effect of flow-induced vibration in causing wear of a tube that touches a foreign body that is trapped inside the tube bundle is to be modeled.

This test setup appears to be suitable for the purpose, but perhaps more complicated than necessary. An equivalent, but simpler, experiment would have the blunt chisel vibrate against the side of the tube at a controlled frequency and with a controlled peak force. However, this comment does not detract from the validity of the actual test to be performed.

2.3.4 Flow-Induced Vibration

In the theoretical discussion of flow-induced vibration, two assumptions were considered concerning the ends of the tubes: fixed-fixed and fixed-pinned. This contrasts with the theoretical models of foreign object impact, in which only fixed-fixed ends were considered. It appears to be more plausible to assumed fixed-pinned ends.

With the flow velocity, about 9 ft/sec, occurring in cross flow, Document 8 shows that stability criteria are satisfied. Since the stability limit is about 15 ft/sec for round tubes with fixed-pinned ends, the margin of safety is adequate, even if the flow geometry has been modified by the removal of some tubes between the tube sheet and the first support plate to such an extent as to increase the local velocity to 10 or 11 ft/sec. Such a large increase is not to be expected.

2.3.5 Tube Collapse

All of the tubes that collapsed were plugged. The first tube to be severed from the tube sheet had a leak, so that collapse due to external pressure did not take place. The mechanism for flattening so that flow-induced vibration can cause fatigue failure need not involve external

BEST DOCUMENT AVAILABLE

pressure, although Document 8 shows that external pressure can be a significant contribution. For some of the collapsed tubes, it may have played an essential role. Collapse (or flattening by impact alone) could have occurred because there was no internal pressure opposing or preventing it. However, even if internal pressure had somehow been provided, thus preventing tube collapse, severe tearing after many impacts by large foreign objects still might not have been prevented. Therefore, removal of foreign objects is necessary, as well as sufficient, to prevent a repetition of the tube burst incident.

BEST DOCUMENT AVAILABLE

3. CONCLUSIONS

3.1 METALLURGICAL

1. The tube burst failure resulted from rubbing-induced wall thinning.

2. Damage to the burst tube and to other tubes was caused by mechanical means, with initial major tube deterioration having been initiated by foreign objects.

3. There was no evidence that embrittlement or corrosion of the tube material contributed to the failure.

4. The sequence of events leading to the failure required foreign object induced deterioration of plugged tubes. Accordingly, an adequate inspection system to monitor the presence of foreign objects should be implemented to preclude another tube burst failure.

3.2 FLOW DYNAMICS

3.2.1 Theoretical Impact Model

The use of "fixed-pinned" tube end conditions may be more appropriate for the models used than the "fixed-fixed" conditions that were used. An alternative model is suggested in which the tube effective spring constant does not enter. Instead, the spring constant representing local tube deformation is included.

For impacting objects of a given shape, the peak energy stored in the spring varies roughly as s^n, where s is the linear size scale factor and n is between 2 and 3. Because of the fairly sensitive dependence on s, the impacting mass that causes incipient plastic deformation does not have to be determined very precisely.

BEST DOCUMENT AVAILABLE

3.2.2 Tampa Flow Model

This flow model is suitable for its intended purposes. It was used to show that the largest foreign object found can remain trapped in a wedge area long enough to strike a peripheral plugged tube many times with enough force to cause it eventually to be flattened. It is also capable of being used with smaller foreign objects, say 0.1 times the size (linear dimension) of the largest one studied, thereby providing experimental verification that peak impacting force is much less than that needed to cause plastic deformation, and confirming that such objects are so highly mobile that they do not impact twice near the same location on a tube.

3.2.3 Flow-Induced Vibration

The stability limit for round tubes with fixed-pinned ends is high enough that it is very unlikely that round tubes will experience excessive flow-induced vibration even if local flow velocities are higher near the region from which tubes have been removed. In the unlikely event that excessive flow-induced vibration were to occur, collisions between tubes would be detected by the acoustic monitoring system to be employed in the future.

3.2.4 Test Models

The two test models shown at Westinghouse Research and Development Center on April 27, 1982 are valid for their intended purposes, although simpler experimental setups may also have served.

3.2.5 Scenario Leading to Tube Rupture

The scenario is reasonable and accounts for the tube rupture. In view of the results obtained, it is reasonable to expect that removal of large foreign objects will prevent the recurrence of the tube burst scenario.

APPENDIX C

Time and Event	Comment
January 25, 1982 *	
9:22 a.m.	
Initial conditions: plant power, 100%; indicated reactor coolant system (RCS) loop pressure, 2197 psig; indicated RCS loop average temperature, 572°F; indicated pressurizer pressure, 2235 psig; other primary and secondary parameters normal; primary-to-secondary leak rate, 0 gpm.	The primary-to-secondary leak rate was last calculated based on air ejector monitor indications on January 7, 1982. Air ejector radiation monitor indications had been essentially constant since January 24, 1982. No known plant operations that would have caused or affected the event were in progress.
9:25 a.m.	
The following alarms were received in the control room: charging pump speed alarm; B steam generator level deviation alarm; B steam generator steam-flow/feed-flow mismatch alarm; pressurizer level and pressure deviation alarms; air ejector radiation monitor (R-15) alarm; pressurizer low pressure alarm (setpoint, 2185 psig).	First indications of the tube rupture in B steam generator. One charging pump, which was in automatic pressurizer level control, was now at its maximum speed. The speed of a second charging pump, which had been on manual control, was increased by the operator. The third charging pump was not operating.
9:26 a.m.	
The Shift Supervisor ordered power reduction. One operator fast closed the turbine control valves; another operator commenced normal boration.	The Shift Supervisor was initially in his office which was located off the main operating area of the control room. He was called to the control room by an operator after the first alarm annunciated.
The following alarms were received in the control room: reactor coolant loop low pressure alarm (set-point, 2064 psig); overtemperature ΔT turbine runback because of decreasing pressurizer pressure; main steam dumps armed alarm.	The overtemperature ΔT setpoint is a computed value which is a function of pressurizer pressure and reactor coolant system average temperature.

*All times in this report are given in Eastern Standard Time.

T nd Event	Comment
9:27 a.m. (about)	
All eight main steam dump valves opened automatically.	Steam dump valves opened in automatic control in response to error signal derived from the difference between RCS coolant reference and average temperature.
The third charging pump was manually started by the operator.	All three charging pumps were running at this time. The RCS pressure and pressurizer level decreased as a result of flow through the rupture (break flow). The rate of indicated decrease was consistent with the break flow and the combined effects of high charging flow and the RCS swell from the turbine down-power transient.
The containment fan-cooler, service-water discharge radiation monitor (R-16) alarmed.	Alarm probably resulted from the proximity of the instrument to the B main steam line in the Intermediate Building.
9:28 a.m.	
Four main steam dump valves closed automatically The following also occurred: pressurizer level low alarm (setpoint, 10.5%); automatic reactor trip on low pressurizer pressure (setpoint 1873 psig adjusted by a rate factor); automatic safety injection (setpoint, 1723 psig); automatic containment isolation as a result of safety injection actuation; main turbine automatic trip on reactor trip; A and B steam generator low level alarms; automatic start of both A and B motor-driven auxiliary feed pumps on safety injection; main feedwater automatic isolation and main feedwater pump automatic trip on containment isolation.	The steam generator low levels resulted from the combined effects of the power reduction, reactor, main turbine and main feedwater pump trips. The RCS depressurization rate increased at this time. The break flow had not increased, but the effects of increasing RCS temperature due to the turbine load reduction were no longer present. Further, all charging pumps automatically tripped as a result of safety injection actuation. Letdown isolation valve LCV427 closed on low pressurizer level; the inservice orifice isolation valve closed on interlock with LCV427 controls.

Time and Event	Comment
9:28 a.m. (continued)	
	The reactor coolant pump (RCP) seal return line isolated on containment isolation. Leakage through the RCP seals pressurized the seal return piping. As shown by pressurizer relief tank (PRT) level indication, the seal return relief lifted. The contribution of this relief to PRT inventory was insignificant.
9:29 a.m.	
The main electrical generator output breakers automatically tripped.	
Both RCPs were manually tripped.	Ginna Emergency Procedures E-1.1 and E-1.4 require tripping RCPs at ≤1715 psig; Westinghouse Owners' Group guidance recommends a lower trip pressure. Licensee requires an RCP trip at a higher pressure because Ginna lacks an environmentally qualified pressure instrument capable of reading these lower pressures.
Pressurizer level indicated about 0%.	
9:29 a.m. (about)	
Both steam supply valves to the turbine-driven auxiliary feedwater pump opened automatically because of low-low level in both steam generators.	
9:30 a.m.	
Four main steam dump valves closed automatically	All steam dumps were now closed.
Initial RCS depressurization stopped at about 1200 psig.	Based on post-event data evaluation, the Task Force concluded a steam bubble may have formed in the reactor vessel upper head at this time. Termination of pressure drop was apparently due to the effects of the establishment of saturation conditions in the reactor vessel upper head along with safety injection.

Event	Comment
9:32 a.m. (about)	
The B motor-driven auxiliary feedwater pump was secured manually.	
The B steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	The turbine-driven auxiliary feedwater pump was now being supplied steam from the A steam generator only.
9:33 a.m.	
The Shift Supervisor notified the NRC Operations Center via the Emergency Notification System (ENS) phone. The Shift Supervisor reported a reactor trip from 100% power as a result of a steam generator tube rupture. The identity of the faulted steam generator and release information was not given at this time.	The Shift Supervisor made the ENS report using the ENS phone in his office. He suspected that the B steam generator contained the fault but chose to confirm the situation before identifying the faulted steam generator to the NRC. After the initial report, a licensed reactor operator, who was not part of the onshift crew, manned the ENS in the control room.
The Shift Supervisor declared an Unusual Event.	The Shift Supervisor declared the Unusual Event during his discussion with the NRC Headquarters Duty Officer; the Plant Superintendent was unaware of this declaration. The declaration of an Unusual Event was made in accordance with the Ginna Emergency Plan Implementing Procedures.
9:35 a.m.	
The NRC Senior Resident Inspector (SRI) arrived in the Ginna control room.	The SRI had been monitoring the ENS in his office since 9:33 a.m.
9:38 a.m.	
NRC Region I was placed in phone communication with the site by the NRC Headquarters Duty Officer (HDO).	The connection was via Federal Telecommunications Systems (FTS) from Region I to the NRC Operations Center then via the ENS to the site.
Various main steam dump valves began to cycle open and closed.	Main steam dump valves were now being operated in the pressure-control mode. The operator was manually controlling these valves to cause a plant cooldown as required by the steam generator tube rupture procedure.

T	nd Event	Comment
9:40 a.m.		
	The B main steam isolation valve (MSIV) was manually closed and the B steam generator was isolated as required by the steam generator tube rupture (SGTR) procedure. Plant cooldown was being maintained by dumping steam from A steam generator to the main condenser.	Along with closing the MSIV, B steam generator isolation included automatic closure of the feedwater supply, blowdown and sample valves on containment isolation, manual closure of its auxiliary feedwater supply, and manual closure of the steam supply valve from B steam generator to the turbine-driven auxiliary feedwater pump. RCS pressure and reactor vessel upper head temperature data indicated that the steam bubble in the reactor vessel upper head had been essentially collapsed by safety injection flow.
	The licensee declared an Alert.	
9:46 a.m.		
	The Ginna Plant Superintendent notified the State of New York, Monroe County, and Wayne County.	
	The A steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	The turbine-driven auxiliary feedwater pump was now secured.
9:48 a.m.		
	The A motor-driven auxiliary feedwater pump was manually stopped to control A steam generator level.	No feedwater pumps were operating at this time.
9:49 a.m.		
	The NRC Headquarters Duty Officer (HDO) notified the Emergency Management Agency (FEMA).	

T.	ıd Event	Comment
9:50 a.m.		
	The steam generator blowdown radiation monitor (R-19) alarmed.	R-19 monitors radiation levels on a section of the blowdown system piping common to both A and B steam generators. The alarm at this time may have been caused by activity from the B steam generator spreading through the system because of steam generator sample valves that the licensee indicated had a history of leaking.
9:53 a.m.		
	The B steam generator power-operated relief valve (PORV) was manually isolated by an auxiliary operator closing a local, upstream, manual valve.	Operators stated that they manually isolated the B steam generator atmospheric PORV to minimize the potential for a release that would result from high steam generator pressure lifting the PORV. The control room operators interpreted the step in the tube rupture procedure which directed them to place the PORV in the manual closed position to mean that the local manual PORV isolation valve should be closed. Closing this isolation valve made the PORV unavailable for use in reducing B steam generator pressure and resulted in five challenges to an unisolable steam generator safety valve.
9:55 a.m.		
	The NRC Region I Incident Response Center was activated.	
	B steam generator narrow-range level indicated offscale high even though all feedwater supplies to the B steam generator had been isolated earlier in the event.	
9:57 a.m.		
	Safety injection initiation circuitry was manually reset; containment isolation was then reset.	Safety injection was reset to permit resetting of the containment isolation signal. Containment isolation was reset to permit restoration of instrument air to the containment. Instrument air would be required to operate various valves inside containment, including the pressurizer power-operated relief valves.

Event	Comment
9:58 a.m.	
The licensee's Emergency Coordinator declared the Ginna Technical Support Center (TSC) fully operational.	Manning of the TSC had begun about 9:35 a.m.
9:59 a.m. (about)	
Instrument air was restored to containment.	Because letdown isolation valve LCV427 fails open on loss of instrument air pressure, it could have opened subsequent to containment isolation. If LCV427 had opened, restoration of instrument air would have caused it to close at this time.
10:00 a.m.	
A and C condensate pumps were manually stopped.	The B condensate pump was still running.
10:03 a.m.	
All main steam dump valves were now closed.	
10:04 a.m.	
One charging pump was manually restarted.	
10:07 a.m.	
As directed by the SGTR procedure, pressurizer PORV PCV430 controls were manually cycled open and closed twice from the control room. RCS pressure, PRT pressure, level and temperature and PORV valve position indication in the control room demonstrated the valve successfully operated.	Shortly after the PORV was operated, pressurizer level increased above the letdown isolation set-point. Letdown isolation valve LCV427 and the selected letdown orifice isolation valve then opened. This resulted in lifting the letdown relief valve and adding water to the PRT. The Task Force determined the letdown relief valve was the major contributor to the PRT water level increase.

T	d Event	Comment
10:08 a.m.		
	Pressurizer PORV PCV430 controls were manually cycled again from the control room and the valve successfully operated.	
10:09 a.m.		
	Pressurizer PORV PCV430 controls were manually cycled again. The valve opened as desired. After the operator placed the controls in the closed position, the valve started to close but then reopened and stuck open.	
	The operator placed the PORV block valve control switch in the closed position. RCS pressure dropped to about 900 psig; pressurizer level increased rapidly.	The rapid rise in pressurizer level exceeded that attributable to safety injection and charging flow and was the first clear indication to the control room staff that a steam bubble had formed in the reactor vessel upper head. This was, in fact, the second time a steam bubble had formed in the upper head region. The bubble grew as RCS pressure dropped.
	The pressurizer relief tank (PRT) high-pressure alarm was received in the control room.	
10:10 a.m.		
	The PRT high-temperature alarm was received in the control room.	
10:11 a.m. (about)		
	PORV block valve PCV516 indicated fully closed; pressurizer level indicated offscale high; safety injection increased RCS pressure.	Operators also closed block valve PCV515 to isolate the other pressurizer PORV, PCV431C.

1 nd Event	Comment
10:17 a.m. The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	
10:19 a.m. (about) One B steam generator safety valve lifted and closed.	Safety injection and charging flow maintained RCS pressure greater than B steam generator pressure, resulting in continued RCS inleakage into the faulted steam generator. RCS pressure exceeded the lowest setpoint of the B steam generator safety valves (nominally, 1085 psig). The B steam generator safety valve may have closed and then started to leak steam after this first opening. The B steam generator safety valve position recorder failed to indicate this or subsequent safety valve lifts. The operators heard these lifts from the control room and estimated their duration based on aural information.
10:26 a.m. The PRT high level alarm was received in the control room.	
10:28 a.m. (about) One B steam generator safety valve lifted and closed.	
10:29 a.m. The A motor-driven auxiliary feedwater pump was manually stopped.	

	Event	Comment
	10:30 a.m.	
	The NRC Headquarters Operations Center was activated.	NRC Headquarters entered its Initial Activation response mode without previously entering the tandby mode. This caused a number of notifications to be delayed.
	10:33 a.m. (about)	
	The licensee dispatched the onsite and offsite radiological survey teams.	The survey teams were formed and dispatched after the Alert declaration instead of the Site Area Emergency declaration as specified in the Ginna Emergency Plan Implementing Procedures. This action was done as a result of procedure improvements identified during the January 21, 1982 emergency drill.
	10:34 a.m.	
	The NRC Headquarters Response Coordination Team notified FEMA that the NRC Operations Center had activated.	
	10:35 a.m.	
	The NRC Executive Director for Operations notified the NRC Chairman about the event.	
		The NRC Commissioners' Assistants were not notified at this time by the NRC Response Coordination Team, as required by NRC incident response procedures.
	10:38 a.m. (about)	
	One B steam generator safety valve lifted and closed.	
	Safety injection was terminated by the operators to prevent further release through the B steam generator safety valve.	Charging flow was maintained.

1 nd Event	Comment
10:40 a.m.	
The B condensate pump and the condensate system were secured; the air ejector secured automatically following loss of condensate flow.	The licensee secured the condensate system to minimize the spread of radioactive contamination to the condensate storage tanks (CSTs) and the condensate demineralizer system. Securing the condensate system made the main condenser unavailable for further dumping of steam.
The A steam generator PORV was manually throttled open to continue the plant cooldown by relieving the A steam generator to atmosphere.	
10:42 a.m. (about)	
A second charging pump was started.	
The pressurizer heaters were re-energized to establish a steam bubble in the pressurizer.	The pressurizer heaters tripped on low pressurizer level during the initial depressurization.
10:44 a.m.	
The licensee declared a Site Area Emergency and executed a site evacuation.	Nonessential personnel were evacuated to the licensee's training center which was downwind of the plant and within the path of the release plume.
10:52 a.m. (about)	
The PRT rupture disc ruptured, releasing water to the A containment sump.	The disc ruptured primarily because of the letdown relief flow; pressurizer PORV openings and RCP seal return relief were minor contributors to the PRT level transient which finally caused the disc rupture.
10:59 a.m.	
The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	From this time in the event, until the plant was cooling down on the residual heat removal system, the A motor-driven auxiliary feedwater pump was run intermittently to control A steam generator water level.

T	d Event	Comment
11:07 a.m. (about)		
One safety injection pump was manually restarted from the control room. The safety injection pump discharge valve was locally throttled to prevent B steam generator safety valve lifts.		The safety injection pump was started in anticipation of an RCS pressure drop that might result from restarting an RCP. This action was not required by the SGTR procedure but was taken as a direct result of the inability to reestablish normal pressurizer pressure control.
11:19 a.m. (about)		
One B steam generator safety valve lifted and closed.		
The process computer failed. It remained out of service until about 11:35 a.m.		The licensee manually read reactor vessel upper head and core exist thermocouples to verify adequate core cooling and to determine subcooling in the core and reactor vessel upper head. Any remaining steam bubble in the reactor vessel upper head region, at this time, would have had a volume of less than 300 ft^3.
11:21 a.m. (about)		
The A RCP was restarted; reactor vessel upper head thermocouple temperatures approached core exit temperatures; pressurizer level indications remained offscale high.		A steam bubble in the reactor vessel upper head region would have been condensed by the cooler loop water now forced into this region. Since the pressurizer level instruments were calibrated for operating conditions, the actual pressurizer level would have to drop below 80% before indicated level would respond. The pressurizer volume above 80% actual level is approximately 200 ft^3.
One charging pump was stopped.		
11:25 a.m.		
The licensee's Offsite Emergency Operations Facility was fully operational.		

T[illegible]nd Event	Comment
11:2[illegible]5 a.m. (continued) The NRC Chairman arrived at the NRC Headquarters Operations Center.	
11:25 a.m. (about) An NRC Headquarters Operations Center representative made initial event notifications to other Federal agencies; e.g., Department of Energy, Health and Human Services, Environmental Protection Agency, and the White House Situation Room.	
11:37 a.m. (about) One B steam generator safety valve lifted and closed; the safety injection pump was stopped.	Based on the indicated pressure differential between the RCS and the B steam generator, and on an RCS inventory balance calculation, the Task Force determined the safety valve failed to fully reseat. It remained partially open until about 12:25 p.m., leaking water at a rate estimated to be about 100 gpm.
11:40 a.m. The NRC Region I Site Team and FEMA personnel departed for the Ginna site. The NRC Region I Administrator was the NRC Site Team Leader.	
11:43 a.m. (about) The plant vent particulate radiation monitor (R-13) and the plant iodine monitor (R-10B) alarmed.	The licensee stated that the R-13 and R-10B monitor alarms were probably caused either by increased background radiation in the vicinity of these monitors or by the Auxiliary Building ventilation system drawing outside air into the building after the steam generator safety valve lifts. It should be noted that no plant noble gas radiation monitor (R-14) alarm was received at this time. The reason this alarm did not occur has not been determined.

Ti ıd Event	Comment
11:46 a.m. Additional NRC offices were notified by personnel in the NRC Headquarters Operations Center; e.g., Commissioners' Assistants (through the Chairman's office), Congressional Affairs.	
11:52 a.m. Pressurizer level indications returned on scale; a steam bubble had been reestablished in the pressurizer.	
11:55 a.m. The NRC Chairman briefed the New York State Governor on the status of the plant and on planned NRC involvement in the event.	
12:02 p.m. Normal letdown was restored.	The maximum rate of change of pressurizer level indication, which occurred about 12:10 p.m., agreed well with that predicted by analysis of the effects of the existing cooldown, charging and letdown rates and the break flow predicted by the Task Force model.
12:12 p.m. (about) One safety injection pump was started from the control room.	The safety injection was restarted to terminate the rapid decrease in pressurizer level. The pump was operated intermittently over the next 23 minutes to control pressurizer level.
12:27 p.m. The RCS and B steam generator indicated pressures equalized.	The B steam generator pressure trend indicated that the B steam generator safety valve reseated completely just before this time.

and Event	Comment
12:34 p.m. (about) The RCP seal water return isolation valve was manually opened.	RCP seal return relief reseated at this time.
12:35 p.m. (about) Intermittent operation of the safety injection pump was stopped.	
1:16 p.m. The A MSIV was manually closed.	
1:30 p.m. The NRC Chairman updated the New York State Governor on plant status and discussed with him the benefits of the state conducting offsite confirmatory radiological monitoring.	
1:52 p.m. The NRC Chairman discussed offsite confirmatory monitoring capabilities with a representative of the New York State Radiological Health Department.	
2:00 p.m. The licensee reported containment sump A level as 9.3 feet (approx. 8000 gallons); PRT level at 92%.	Containment sump A has two channels of level indication. Channel 1 indicated 5.3 feet (1,900 gallons); channel 2 indicated 9.3 feet (8,000 gallons). Later, it was discovered that channel 2 was in error.
2:25 p.m. The NRC Chairman appointed the NRC Executive Director for Operations as Acting Executive Team Director and left the NRC Headquarters Operations Center.	

BEST DOCUMENT AVAILABLE

T nd Event	Comment
4:15 p.m.	
The NRC Region I Incident Response Site Team arrived onsite at Ginna.	The delay in the Site Team reaching the Ginna site resulted from poor weather conditions in the Rochester area.
5:00 p.m.	
The NRC Region I Administrator was appointed Director of Site Operations (DSO) with full authority to act for the Commission at the site.	New York State Governor, NRC Chairman, the other NRC Commissioners, and other federal and state agencies were notified of the transfer of authority to the DSO.
6:40 p.m. (about)	
Narrow-range water level indication for the B steam generator returned to the indicating range. Plant cooldown continued via the A steam generator PORV with the A RCP providing flow through the A loop and backflow through the B loop. The operators maintained indicated RCS pressure 25 psi below B steam generator pressure. The B steam generator was being cooled by intermittently feeding it with auxiliary feedwater while bleeding it via the ruptured tube to the RCS.	The plant staff was concerned that water in the B main steam line might flash to steam if the steam generator was cooled and depressurized too quickly. Flashing in the main steam lines could have caused a water hammer, which could have overstressed the main steam line hangers. Therefore, the plant staff decided to pin these hangers and to conduct a slow cooldown. Because of an instrument calibration error in the RCS loop pressure instrument, the actual RCS-to-B steam generator pressure differential was about 3 psi and very little steam generator-to-RCS flow existed.

T[illegible]nd Event	Comment
6:40 p.m. (continued)	To provide warning of excessive boron dilution in the RCS as a result of the B steam generator feed-and-bleed process, the plant staff sampled the RCS for boron concentration at half-hour intervals. The feed-and-bleed cooldown process caused the level in the CVCS Holdup Tanks to increase and the the plant staff discussed the consequences of these tanks filling. The capacity of these tanks was not approached.
7:04 p.m. An operator again attempted to shut pressurizer PORV PCV430; the valve remained open.	
7:17 p.m. The licensee downgraded the Site Area Emergency to an Alert.	
January 26, 1982	
7:00 a.m. (about) The residual heat removal (RHR) system was placed in service to continue the plant cooldown. The A RCP remained in operation.	The RCP remained in operation to assist in RCS degasification and cleanup in preparation for opening the primary-side manway on B steam generator. At low steam pressures in the A steam generator, the capacity of the A steam generator PORV had limited the plant cooldown rate.
10:45 a.m. The licensee downgraded the Alert to the Recovery phase.	Chapter 7 discusses occurrences after this time.

BEST DOCUMENT AVAILABLE

NRC FORM 335 (7-77) U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

1. REPORT NUMBER (Assigned by DDC): NUREG-0916

4. TITLE AND SUBTITLE (Add Volume No., if appropriate): Safety Evaluation Report related to Restart of R. E. Ginna Nuclear Power Plant

2. (Leave blank)

3. RECIPIENT'S ACCESSION NO.

7. AUTHOR(S)

5. DATE REPORT COMPLETED: MONTH May YEAR 1982

9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
U. S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555

DATE REPORT ISSUED: MONTH May YEAR 1982

6. (Leave blank)

8. (Leave blank)

12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
Same as 9, above.

10. PROJECT/TASK/WORK UNIT NO.

11. CONTRACT NO.

13. TYPE OF REPORT: Staff's Technical Evaluation

PERIOD COVERED (Inclusive dates): January 1982 - May 1982

15. SUPPLEMENTARY NOTES: Related to Docket No. 50-244

14. (Leave blank)

16. ABSTRACT (200 words or less)

This report documents NRC's evaluation of the tube rupture which occurred at the R. E. Ginna Nuclear Power Plant on January 25, 1982. This plant, which is located in Wayne County, New York, is owned and operated by Rochester Gas and Electric Corporation. In NUREG-0916, the staff has determined, based on conclusions reached in Section 10.0, that operation of the Ginna plant would be acceptable subject to the commitments contained in Section 9.0 of that report which, as summarized below, have been incorporated into the license as conditions.

17. KEY WORDS AND DOCUMENT ANALYSIS

17a. DESCRIPTORS

17b. IDENTIFIERS/OPEN-ENDED TERMS

18. AVAILABILITY STATEMENT: Unlimited

19. SECURITY CLASS (This report): Unclassified

21. NO. OF PAGES

20. SECURITY CLASS (This page): Unclassified

22. PRICE: $

NRC FORM 335 (7-77)

BEST DOCUMENT AVAILABLE